PB80-194913

Standards of Performance for New Stationary Sources - A Compilation as of January 1, 1979

PEDCo-Environmental, Inc.
Cincinnati, OH

Prepared for

Environmental Protection Agency
Washington, DC

Jan 79

U.S. Department of Commerce
National Technical Information Service
NTIS

PB80-194913

STANDARD OF PERFORMANCE FOR NEW STATIONARY SOURCES - AS OF JANUARY 1, 1979

(First Supplemental Information Packet for Updating November 1977 NSPS Regulations Compilation, EPA-340/1-77-015)

Stationary Source Enforcement Series

EPA-340/1-79-001
January 1979

U.S. ENVIRONMENTAL PROTECTION AGENCY
OFFICE OF ENFORCEMENT
OFFICE OF GENERAL ENFORCEMENT
WASHINGTON, D.C. 20460

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA 340/1-79-001	2.	3. RECIPIENT'S ACCESSION NO. PB80 194913
4. TITLE AND SUBTITLE Standards of Performance for New Stationary Sources- A Compilation as of January 1, 1979		5. REPORT DATE January 1979
		6. PERFORMING ORGANIZATION CODE P/N 3370-3-DD
7. AUTHOR(S)		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo Environmental, Inc. 11499 Chester Road Cincinnati, Ohio 45246		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO. 68-01-4147, Task 73
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Division of Stationary Source Enforcement Washington, DC 20460		13. TYPE OF REPORT AND PERIOD COVERED Supplement, Nov. 1977 to Jan. 1979
		14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

DSSE Project Officer: Kirk Foster

Reproduced from best available copy.

16. ABSTRACT

This document contains those pages necessary to update Standards of Performance for New Stationary Sources - A Compilation, published by the U.S. Environmental Protection Agency, Division of Stationary Source Enforcement in November 1977 (EPA 340/1-77-015). It is only an update and should be used in conjunction with the original compilation.

Included in the update, with complete instructions for filing, are: a new cover, title page, and table of contents; a new summary table; all revised and new Standards of Performance; the full text of all revisions and standards promulgated since November 1977; and all proposed standards or revisions.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Federal Emission Standards Regulations Enforcement	New Source Performance Standards	13B 14D

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

★U.S. GOVERNMENT PRINTING OFFICE: 1979-640-013/4224 REGION NO. 4

EPA-340/1-77-015
EPA-340/1-79-001

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES -

A COMPILATION AS OF JANUARY 1, 1979

by

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Contract No. 68-01-4147

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Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Enforcement
Office of General Enforcement
Division of Stationary Source Enforcement
Washington, D.C. 20460

January 1979

January 1979

To holders of Standards of Performance for New Stationary Sources, A Compilation:

This document contains those pages necessary to update the above mentioned publication through January 1, 1979. It is only an update and should be used in conjunction with the original compilation published by the U.S. Environmental Protection Agency, Division of Stationary Source Enforcement in November 1977 (EPA 340/1-77-015). Copies of Standards of Performance for New Stationary Sources, A Compilation may be obtained from:

U.S. Environmental Protection Agency
Office of Adminstration
General Services Division, MD-35
Research Triangle Park, NC 27711

Included in this update, with complete instructions for filing, are: a new cover, title page, and table of contents; a new Summary Table; all revised and new Standards of Performance; the full text of all revisions and standards promulgated since November 1977; and all proposed standards or revisions.

Any questions, comments or suggestions regarding this document or the previous compilation should be directed to: Standards Handbooks, Division of Stationary Source Enforcement (EN-341), U.S. Environmental Protection Agency, Washington, D.C., 20460.

INSTRUCTIONS FOR FILING

Remove and discard the cover and title page of this document.

Deletions	Additions
Cover and title page dated November 1977	Cover and title page dated January 1979
Table of Contents: pages v through xv	Table of Contents: pages v through xviii
Section II, Summary: pages II-3 through 11	Section II, Summary: pages II-3 through 18
Section III, Standards: pages III-1 through 46	Section III, Standards: pages III-1 through 51
Section III, Appendix A: pages A-1 through A-34	Section III, Appendix A: pages A-1 through A-34
pages A-41 through A-54	pages A-41 through A-78
Section III, Appendix B: pages B-11 and 12	Section III, Appendix B: pages B-11 and 12
Section III, Appendix C: page C-1	Section III, Appendix C: page C-1
Section III, Appendix D: page D-1	Section III, Appendix D: page D-1
Section IV, Full Text: pages vii and viii	Section IV, Full Text: pages vii through x
page IV-207	pages IV-207 through 278
Section V, Proposed Amendments: All proposed items have been promulgated, therefore: Remove all pages from Section V	Section V, Proposed Amendments: New or amended regulations have been proposed for:
	Subpart A - General Provisions
	Subpart D, Da - Electric Utility Steam Generating Units
	Subpart K, Ka - Petroleum Liquid Storage Vessels
	Subpart S - Primary Aluminum Industry
	Subpart GG - Stationary Gas Turbines

Place the new Technical Report Data page and this page in the back for future reference.

TABLE OF CONTENTS

Page

I. INTRODUCTION TO STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES I-1

II. SUMMARY OF STANDARDS AND REVISIONS II-1

III. PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES III-1

SUBPART A - GENERAL PROVISIONS

Section

60.1 Applicability III-3

60.2 Definitions III-3

60.3 Abbreviations III-3

60.4 Address III-4

60.5 Determination of construction or modification III-5

60.6 Review of plans III-5

60.7 Notification and recordkeeping III-5

60.8 Performance tests III-6

60.9 Availability of information III-6

60.10 State authority III-6

60.11 Compliance with standards and maintenance requirements III-6

60.12 Circumvention III-7

60.13 Monitoring requirements III-7

60.14 Modification III-8

60.15 Reconstruction III-10

SUBPART B - ADOPTION AND SUBMITTAL OF STATE PLANS FOR DESIGNATED FACILITIES

Section

60.20 Applicability III-11

60.21 Definitions III-11

60.22 Publication of guideline documents, emission guidelines, final compliance times III-11

TABLE OF CONTENTS

Page

Section

60.23 Adoption and submittal of state plans; public hearings III-11

60.24 Emission standards and compliance schedules III-12

60.25 Emission inventories, source surveillance reports III-12

60.26 Legal authority III-13

60.27 Actions by the Administrator III-13

60.28 Plan revisions by the State III-13

60.29 Plan revisions by the Administrator III-13

SUBPART C - EMISSION GUIDELINES AND COMPLIANCE TIMES III-14

SUBPART D - STANDARDS OF PERFORMANCE FOR FOSSIL-FUEL FIRED STEAM GENERATORS

Section

60.40 Applicability and designation of affected facility III-15

60.41 Definitions III-15

60.42 Standard for particulate matter III-15

60.43 Standard for sulfur dioxide III-15

60.44 Standard for nitrogen oxides III-15

60.45 Emission and fuel monitoring III-15

60.46 Test methods and procedures III-17

SUBPART E - STANDARDS OF PERFORMANCE FOR INCINERATORS

Section

60.50 Applicability and designation of affected facility III-18

60.51 Definitions III-18

60.52 Standard for particulate matter III-18

TABLE OF CONTENTS

Section | Page

60.53 Monitoring of operations III-18

60.54 Test methods and procedures III-18

SUBPART F - STANDARDS OF PERFORMANCE FOR PORTLAND CEMENT PLANTS

Section

60.60 Applicability and designation of affected facility III-19

60.61 Definitions III-19

60.62 Standard for particulate III-19

60.63 Monitoring of operations III-19

60.64 Test methods and procedures III-19

SUBPART G - STANDARDS OF PERFORMANCE FOR NITRIC ACID PLANTS

Section

60.70 Applicability and designation of affected facility III-20

60.71 Definitions III-20

60.72 Standard for nitrogen oxides III-20

60.73 Emission monitoring III-20

60.74 Test methods and procedures III-20

SUBPART H - STANDARDS OF PERFORMANCE FOR SULFURIC ACID PLANTS

Section

60.80 Applicability and designation of affected facility III-21

60.81 Definitions III-21

60.82 Standard for sulfur dioxide III-21

60.83 Standard for acid mist III-21

60.84 Emission monitoring III-21

60.85 Test methods and procedures III-21

TABLE OF CONTENTS

Page

SUBPART I - STANDARDS OF PERFORMANCE FOR ASPHALT CONCRETE PLANTS

Section

60.90 Applicability and designation of affected facility III-22
60.91 Definitions III-22
60.92 Standard for particulate matter III-22
60.93 Test methods III-22

SUBPART J - STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES

Section

60.100 Applicability and designation of affected facility III-23
60.101 Definitions III-23
60.102 Standard for particulate matter III-23
60.103 Standard for carbon monoxide III-23
60.104 Standard for sulfur dioxide III-23
60.105 Emission monitoring III-23
60.106 Test methods and procedures III-23

SUBPART K - STANDARDS OF PERFORMANCE FOR STORAGE VESSELS FOR PETROLEUM LIQUIDS

Section

60.110 Applicability and designation of affected facility III-25
60.111 Definitions III-25
60.112 Standard for hydrocarbons III-25
60.113 Monitoring of operations III-25

SUBPART L - STANDARDS OF PERFORMANCE FOR SECONDARY LEAD SMELTERS

Section

60.120 Applicability and designation of affected facility III-26

12

TABLE OF CONTENTS

Page

Section

60.121 Definitions III-26

60.122 Standard for particulate matter III-26

60.123 Test methods and procedures III-26

SUBPART M - STANDARDS OF PERFORMANCE FOR SECONDARY BRASS AND BRONZE INGOT PRODUCTION PLANTS

Section

60.130 Applicability and designation of affected facility III-27

60.131 Definitions III-27

60.132 Standard for particulate matter III-27

60.133 Test methods and procedures III-27

SUBPART N - STANDARDS OF PERFORMANCE FOR IRON AND STEEL PLANTS

Section

60.140 Applicability and designation of affected facility III-28

60.141 Definitions III-28

60.142 Standard for particulate matter III-28

60.143 Monitoring of operations III-28

60.144 Test methods and procedures III-28

SUBPART O - STANDARDS OF PERFORMANCE FOR SEWAGE TREATMENT PLANTS

Section

60.150 Applicability and designation of affected facility III-29

60.151 Definitions III-29

60.152 Standard for particulate matter III-29

60.153 Monitoring of operations III-29

60.154 Test methods and procedures III-29

TABLE OF CONTENTS

Page

SUBPART P - STANDARDS OF PERFORMANCE FOR PRIMARY COPPER SMELTERS

Section

60.160 Applicability and designation of affected facility III-30
60.161 Definitions III-30
60.162 Standard for particulate matter III-30
60.163 Standard for sulfur dioxide III-30
60.164 Standard for visible emissions III-30
60.165 Monitoring of operations III-30
60.166 Test methods and procedures III-31

SUBPART Q - STANDARDS OF PERFORMANCE FOR PRIMARY ZINC SMELTERS

Section

60.170 Applicability and designation of affected facility III-32
60.171 Definitions III-32
60.172 Standard for particulate matter III-32
60.173 Standard for sulfur dioxide III-32
60.174 Standard for visible emissions III-32
60.175 Monitoring of operations III-32
60.176 Test methods and procedures III-32

SUBPART R - STANDARDS OF PERFORMANCE FOR PRIMARY LEAD SMELTERS

Section

60.180 Applicability and designation of affected facility III-33
60.181 Definitions III-33
60.182 Standard for particulate matter III-33
60.183 Standard for sulfur dioxide III-33
60.184 Standard for visible emissions III-33
60.185 Monitoring of operations III-33
60.186 Test methods and procedures III-33

14

TABLE OF CONTENTS

Page

SUBPART S - STANDARDS OF PERFORMANCE FOR PRIMARY ALUMINUM REDUCTION PLANTS

Section

60.190 Applicability and designation of affected facility III-34
60.191 Definitions III-34
60.192 Standard for fluorides III-34
60.193 Standard for visible emissions III-34
60.194 Monitoring of operations III-34
60.195 Test methods and procedures III-34

SUBPART T - STANDARDS OF PERFORMANCE FOR PHOSPHATE FERTILIZER INDUSTRY: WET PROCESS PHOSPHORIC ACID PLANTS

Section

60.200 Applicability and designation of affected facility III-36
60.201 Definitions III-36
60.202 Standard for fluorides III-36
60.203 Monitoring of operations III-36
60.204 Test methods and procedures III-36

SUBPART U - STANDARDS OF PERFORMANCE FOR PHOSPHATE FERTILIZER INDUSTRY: SUPERPHOSPHORIC ACID PLANTS

Section

60.210 Applicability and designation of affected facility III-37
60.211 Definitions III-37
60.212 Standard for fluorides III-37
60.213 Monitoring of operations III-37
60.214 Test methods and procedures III-37

TABLE OF CONTENTS

Page

SUBPART V - STANDARDS OF PERFORMANCE FOR PHOSPHATE FERTILIZER INDUSTRY: DIAMMONIUM PHOSPHATE PLANTS

Section

60.220 Applicability and designation of affected facility III-38
60.221 Definitions III-38
60.222 Standard for fluorides III-38
60.223 Monitoring of operations III-38
60.224 Test methods and procedures III-38

SUBPART W - STANDARDS OF PERFORMANCE FOR PHOSPHATE FERTILIZER INDUSTRY: TRIPLE SUPERPHOSPHATE PLANTS

Section

60.230 Applicability and designation of affected facility III-39
60.231 Definitions III-39
60.232 Standard for fluorides III-39
60.233 Monitoring of operations III-39
60.234 Test methods and procedures III-39

SUBPART X - STANDARDS OF PERFORMANCE FOR THE PHOSPHATE FERTILIZER INDUSTRY: GRANULAR TRIPLE SUPERPHOSPHATE STORAGE FACILITIES

Section

60.240 Applicability and designation of affected facility III-40
60.241 Definitions III-40
60.242 Standard for fluorides III-40
60.243 Monitoring of operations III-40
60.244 Test methods and procedures III-40

TABLE OF CONTENTS

Page

SUBPART Y - STANDARDS OF PERFORMANCE FOR COAL PREPARATION PLANTS

Section

60.250 Applicability and designation of affected facility III-41
60.251 Definitions III-41
60.252 Standards for particulate matter III-41
60.253 Monitoring of operations III-41
60.254 Test methods and procedures III-41

SUBPART Z - STANDARDS OF PERFORMANCE FOR FERROALLOY PRODUCTION FACILITIES

Section

60.260 Applicability and designation of affected facility III-42
60.261 Definitions III-42
60.262 Standard for particulate matter III-42
60.263 Standard for carbon monoxide III-42
60.264 Emission monitoring III-42
60.265 Monitoring of operations III-42
60.266 Test methods and procedures III-43

SUBPART AA - STANDARDS OF PERFORMANCE FOR STEEL PLANTS: ELECTRIC ARC FURNACES

Section

60.270 Applicability and designation of affected facility III-45
60.271 Definitions III-45
60.272 Standard for particulate matter III-45
60.273 Emission monitoring III-45
60.274 Monitoring of operations III-45
60.275 Test methods and procedures III-46

TABLE OF CONTENTS

Page

SUBPART BB - STANDARDS OF PERFORMANCE FOR KRAFT PULP MILLS

Section

60.280 Applicability and designation of affected facility III-47
60.281 Definitions III-47
60.282 Standard for particulate matter III-47
60.283 Standard for total reduced sulfur (TRS) III-47
60.284 Monitoring of emissions and operations III-48
60.285 Test methods and procedures III-48

SUBPART DD - STANDARDS OF PERFORMANCE FOR GRAIN ELEVATORS

Section

60.300 Applicability and designation of affected facility III-50
60.301 Definitions III-50
60.302 Standard for particulate matter III-50
60.303 Test methods and procedures III-50
60.304 Modification III-50

SUBPART HH - STANDARDS OF PERFORMANCE FOR LIME MANUFACTURING PLANTS

60.340 Applicability and designation of affected facility III-51
60.341 Definitions III-51

18

Section		Page
60.342	Standard for particulate matter	III-51
60.343	Monitoring of emissions and operations	III-51
60.344	Test methods and procedures	III-51

TABLE OF CONTENTS

Page

APPENDIX A - REFERENCE METHODS

Method 1 - Sample and velocity traverses for stationary sources III-Appendix A-1

Method 2 - Determination of stack gas velocity and volumetric flow rate (Type S Pitot Tube) III-Appendix A-4

Method 3 - Gas analysis for carbon dioxide, excess air, and dry molecular weight III-Appendix A-14

Method 4 - Determination of moisture in stack gases III-Appendix A-17

Method 5 - Determination of particulate emissions from stationary sources III-Appendix A-21

Method 6 - Determination of sulfur dioxide emissions from stationary sources III-Appendix A-28

Method 7 - Determination of nitrogen oxide emissions from stationary sources III-Appendix A-30

Method 8 - Determination of sulfuric acid mist and sulfur dioxide emissions from stationary sources III-Appendix A-32

Method 9 - Visual determination of the opacity of emissions from stationary sources III-Appendix A-35

Method 10 - Determination of carbon monoxide emissions from stationary sources III-Appendix A-39

Method 11 - Determination of hydrogen sulfide content of fuel gas streams in petroleum refineries III-Appendix A-41

Method 12 - [Reserved]

Method 13A - Determination of total fluoride emissions from stationary sources - SPADNS Zircomium Lake method III-Appendix A-45

Method 13B - Determination of total fluoride emissions from stationary sources - Specific Ion Electrode method III-Appendix A-51

Method 14 - Determination of fluoride emissions from potroom roof monitors of primary aluminum plants III-Appendix A-55

Page

Method 15 - Determination of hydrogen sulfide, carbonyl sulfide, and carbon desulfide emissions from stationary sources III-Appendix A-57

Method 16 - Semicontinuous determination of sulfur emissions from stationary sources III-Appendix A-60

Method 17 - Determination of particulate emissions from stationary sources (in-stack filtration method) III-Appendix A-68

TABLE OF CONTENTS

Page

APPENDIX B - PERFORMANCE SPECIFICATIONS III-Appendix B-1

APPENDIX C - DETERMINATION OF EMISSION RATE CHANGE III-Appendix C-1

APPENDIX D - REQUIRED EMISSION INVENTORY INFORMATION III-Appendix D-1

IV. FULL TEXT OF REVISIONS (References) IV-1

V. PROPOSED AMENDMENTS V-1

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart D - Fossil-Fuel Fired Steam Generators				
Proposed/effective 8/17/71 (36 FR 15704) Promulgated 12/23/71 (36 FR 24876)	Coal, coal/wood residue fired boilers >250 million Btu/hr	Particulate Opacity SO_2 NO_x	0.10 lb/10^6 Btu 20%; 27% 6 min/hr 1.2 lb/10^6 Btu 0.70 lb/10^6 Btu	No requirement Continuous Continuous* Continuous*
Revised 7/26/72 (37 FR 14877) 10/15/73 (38 FR 28564) 6/14/74 (39 FR 20790) 1/16/75 (40 FR 2803) 10/6/75 (40 FR 46250) 12/22/75 (40 FR 59204) 11/22/76 (41 FR 51397) 1/31/77 (42 FR 5936) 7/25/77 (42 FR 37936) 8/15/77 (42 FR 41122) 8/17/77 (42 FR 41122) 12/5/77 (42 FR 61537) 3/3/78 (43 FR 8800) 3/7/78 (43 FR 9276)	Oil, oil/wood residue fired boilers >250 million Btu/hr	Particulate Opacity SO_2 NO_x	0.10 lb/10^6 Btu 20%, 27% 6 min/hr 0.80 lb/10^6 Btu 0.30 lb/10^6 Btu	No requirement Continuous Continuous* Continuous*
	Gas, gas/wood residue fired boilers >250 million Btu/hr	Particulate Opacity NO_x	0.10 lb/10^6 Btu 20%; 27% 6 min/hr 0.20 lb/10^6 Btu	No requirement Continuous* Continuous*
	Mixed fossil fuel fired boilers >250 million Btu/hr	Particulate Opacity SO_2 NO_x (except lignite or 25% coal refuse)	0.10 lb/10^6 Btu 20%; 27% 6 min/hr Prorated Prorated	No requirement Continuous Continuous* Continuous*
	Lignite, lignite/wood residue >250 million Btu/hr	Particulate Opacity SO_2 NO_x (as of 12/22/76)	0.10 lb/10^6 Btu 20%; 27% 6 min/hr 1.2 lb/10^6 Btu 0.60 lb/10^6 Btu 0.80 lb/10^6 Btu for ND, SD, MT lignite burned in cyclone-fired unit	No requirement Continuous Continuous* Continuous*
				*exceptions; see standards

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart E - Incinerators				
Proposed/effective 8/17/71 (36 FR 15704)	Incinerators >50 tons/day	Particulate	0.08 gr/dscf (0.18 g/dscm) corrected to 12% CO_2	No requirement
Promulgated 12/23/71 (36 FR 24876)				Daily charging rates and hours
Revised 6/14/74 (36 FR 20790) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart F - Portland Cement Plants				
Proposed/effective 8/17/71 (36 FR 15704)	Kiln	Particulate Opacity	0.30 lb/ton 20%	No requirement No requirement
Promulgated 12/23/71 (36 FR 24876)	Clinker cooler	Particulate Opacity	0.10 lb/ton 10%	No requirement No requirement
Revised 6/14/74 (39 FR 20790) 11/12/74 (39 FR 39872) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Fugitive emission points	Opacity	10%	No requirement Daily production and feed kiln rates

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart G - Nitric Acid Plants				
Proposed/effective 8/17/71 (36 FR 15704)	Process equipment	Opacity NO_x	10% 3.0 lb/ton	No requirement Continuous
Promulgated 12/23/71 (36 FR 24876)				
Revised 5/23/73 (38 FR 13562) 10/15/73 (38 FR 28564) 6/14/74 (39 FR 20790) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				Daily production rates and hours
Subpart H - Sulfuric Acid Plants				
Proposed/effective 8/17/71 (36 FR 15704)	Process equipment	SO_2 Acid mist Opacity	4.0 lb/ton 0.15 lb/ton 10%	Continuous No requirement No requirement
Promulgated 12/23/71 (36 FR 24876)				
Revised 5/23/73 (38 FR 13562) 10/15/73 (38 FR 28564) 6/14/74 (39 FR 20790) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emisison level	Monitoring requirement
Subpart I - Asphalt Concrete Plants				
Proposed/effective 6/11/73 (38 FR 15406)	Dryers; screening and weighing systems; storage, transfer, and loading systems; and dust handling equipment	Particulate	0.04 gr/dscf (90 mg/dscm)	No requirement
Promulgated 3/8/74 (39 FR 9308)		Opacity	20%	No requirement
Revised 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart J - Petroleum Refineries				
Proposed/effective	Catalytic cracker	Particulate	1.0 lb/1000 lb (1.0 kg/1000 kg)	No requirement
6/11/73 (38 FR 15406) 10/4/76 (41 FR 43866)		Opacity	30% (6 min. exemption)	Continuous
	With incinerator or waste heat boiler	Particulate	Additional 0.10 lb/million Btu (43.0 g/MJ)	No requirement
		CO	0.05%	Continuous
Promulgated 3/8/74 (39 FR 9308)	Fuel gas combustion	SO_2	0.10 gr H_2S/dscf (230 mg/dscm) fuel gas content	Continuous
Revised 10/6/75 (40 FR 46250) 6/24/77 (42 FR 32426) 7/25/77 (42 FR 37936) 8/4/77 (42 FR 39389) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800) 3/15/78 (43 FR 10866)	Claus sulfur recovery plants >20 LTD/day (as of 10/4/76)	SO_2	0.025% with oxidation or reduction and incineration 0.030% with reduction only	Continuous Continuous

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart K - Storage Vessels for Petroleum Liquids				
Proposed/effective 6/11/73 (38 FR 15406) Promulgated 3/8/74 (39 FR 9308)	Storage tanks >40,000 gal. capacity	Hydrocarbons	For vapor pressure 78-570 mm Hg (1.5 psia-11.1 psia), equip with floating roof, vapor recovery system, or equivalent; for vapor pressure >570 mm Hg (11.1 psia), equip with vapor recovery system or equivalent	No requirement Date, type, vapor pressure and temperature
Revised 4/17/74 (39 FR 13776) 6/14/74 (39 FR 20790) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart L - Secondary Lead Smelters				
Proposed/effective 6/11/73 (38 FR 15406)	Reverberatory and blast furnaces	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
		Opacity	20%	No requirement
Promulgated 3/8/74 (39 FR 9308)	Pot furnaces >550 lb/capacity	Opacity	10%	No requirement
Revised 4/17/74 (39 FR 13776) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart M - Secondary Brass, Bronze and Ingot Production Plants				
Proposed/effective 6/11/73 (38 FR 15406)	Reverberatory furnace	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
		Opacity	20%	No requirement
Promulgated 3/8/74 (39 FR 9308)	Blast and electric furnaces	Opacity	10%	No requirement
Revised 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart N - Iron and Steel Plants				
Proposed/effective 6/11/73 (38 FR 15406)	Basic oxygen process furnace	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
Promulgated 3/8/74 (39 FR 9308)		Opacity	10% (20% exception/cycle)	No requirement
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800) 4/13/78 (43 FR 15600)				Time and duration of each cycle; exhaust gas diversion; scrubber pressure loss; water supply pressure

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart O - Sewage Treatment Plants				
Proposed/effective 6/11/73 (38 FR 15406) 3/8/74 (39 FR 9308)	Sludge incinerators >10% from municipal sewage treatment or >2,205 lb/day municipal sewage sludge	Particulate	1.30 lb/ton (0.65 g/kg)	No requirement
		Opacity	20%	No requirement
Revised 4/17/74 (39 FR 13776) 5/3/74 (39 FR 15396) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424)				Mass or volume of sludge; mass of any municipal solid waste
Subpart P - Primary Copper Smelters				
Proposed/effective 10/16/74 (39 FR 37040)	Dryer	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
		Opacity	20%	Continuous
Promulgated 1/15/76 (41 FR 2331)	Roaster, smelting furnace,* copper converter	SO_2	0.065%	Continuous
		Opacity	20%	No requirement
Revised 2/26/76 (41 FR 8346) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	*Reverberatory furnaces that process high-impurity feed materials are exempt from SO_2 standard			Monthly record of charge and weight percent of arsenic, antimony, lead, and zinc

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart Q - Primary Zinc Smelters				
Proposed/effective 10/16/74 (39 FR 37040)	Sintering machine	Particulate	0.022 gr/dscf (50 mg/dscm)	**No requirement**
		Opacity	20%	**Continuous**
Promulgated 1/51/76 (41 FR 2331)	Roaster	SO_2	0.065%	**Continuous**
		Opacity	20%	**No requirement**
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart R - Primary Lead Smelters				
Proposed/effective 10/16/74 (39 FR 37040)	Blast or reverberatory furnace, sintering machine discharge end	Particulate	0.022 gr/dscf (50 mg/dscm)	**No requirement**
		Opacity	20%	**Continuous**
Promulgated 1/15/76 (41 FR 2331)	Sintering machine, electric smelting furnace, converter	SO_2	0.065%	**Continuous**
		Opacity	20%	**No requirement**
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart S - Primary Aluminum Reduction Plants				
Proposed/effective 10/23/74 (39 FR 37730)	Potroom group	Opacity	10%	No requirement
		Total fluorides		
		(a) Soderberg	2.0 lb/ton	No requirement
Promulgated 1/26/76 (41 FR 3825)		(b) Prebake	1.9 lb/ton	No requirement
	Anode bake plants	Total fluorides	0.1 lb/ton	No requirement
		Opacity	20%	No requirement
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				Daily weight, production rate of aluminum and anode raw material feed rate, cell or potline voltages
Subpart T - Phosphate Fertilizer Industry				
Proposed/effective 10/22/74 (39 FR 37602)	Wet process phosphoric acid	Total fluorides	0.02 lb/ton	No requirement
Promulgated 8/6/75 (40 FR 33152)				Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart U - Phosphate Fertilizer Industry				
Proposed/effective 10/22/74 (39 FR 37602)	Superphosphoric acid	Total fluorides	0.01 lb/ton	No requirement
Promulgated 8/6/75 (40 FR 33152)				Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart V - Phosphate Fertilizer Industry				
Proposed/effective 10/24/74 (39 FR 37602)	Diammonium phosphate	Total fluorides	0.06 lb/ton	No requirement
Promulgated 8/6/75 (40 FR 33152)				Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart W - Phosphate Fertilizer Industry Proposed/effective 10/22/74 (39 FR 37602) Promulgated 8/6/75 (40 FR 33152) Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Triple superphosphate	Total fluorides	0.2 lb/ton	No requirement Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system
Subpart X - Phosphate Fertilizer Industry Proposed/effective 10/22/74 (39 FR 37602) Promulgated 8/6/75 (40 FR 33152) Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Granular triple superphosphate	Total fluorides	5.0×10^{-4} lb/hr/ton	No requirement Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart Y - Coal Preparation Plants				
Proposed/effective 10/24/74 (39 FR 37922)	Thermal dryer	Particulate	0.031 gr/dscf (0.070 g/dscm)	Temperature, Scrubber pressure loss, Water pressure
Promulgated 1/15/76 (41 FR 2232)		Opacity	20%	No requirement
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 9/7/77 (42 FR 44812) 3/3/78 (43 FR 8800)	Pneumatic coal cleaning equipment	Particulate	0.018 gr/dscf (0.040 g/dscm)	No requirement
		Opacity	10%	No requirement
	Processing and conveying equipment, storage systems, transfer and loading systems	Opacity	20%	No requirement

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart Z - Ferroalloy Production Facilities Proposed/effective 10/21/74 (39 FR 37470) Promulgated 5/4/76 (41 FR 18497) Revised 5/20/76 (41 FR 20659) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Electric submerged arc furnaces	Particulate	0.99 lb/MW-hr (0.45 kg/MW-hr) ("high silicon alloys") 0.51 lb/MW-hr (0.23 kg/MW-hr) (chrome and manganese alloys)	No requirement
			No visible emissions may escape furnace capture system	Flowrate monitoring in hood
			No visible emission may escape tapping system for >40% of each tapping period	Flowrate monitoring in hood
		Opacity	15%	Continuous
		CO	20% volume basis	No requirement
	Dust handling equipment	Opacity	10%	No requirement

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart AA - Steel Plants Proposed/effective 10/21/74(39 FR 37466) Promulgated 9/23/75 (40 FR 43850) Revised 7/25/77 (40 FR 37936) 8/17/77 (42 FR 41424) 9/7/77 (42 FR 44812) 3/3/78 (43 FR 8800)	Electric arc furnaces	Particulate	0.0052 gr/dscf (12 mg/dscm)	No requirement
		Opacity (a) control device (b) shop roof	3% 0% except <20%-charging <40%-tapping	Continuous Flowrate monitoring in capture hood, Pressure monitoring in DSE system
	Dust handling equipment	Opacity	10%	No requirement

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart BB - Kraft Pulp Mills				
Proposed/effective 9/24/76 (41 FR 42012)	Recovery furnace	Particulate	0.044 gr/dscf (0.10 g/dscm) corrected to 8% oxygen	No requirement
Promulgated 2/23/78 (43 FR 7568)		Opacity	35%	Continuous
Revised 8/7/78 (43 FR 34784)		TRS (a) straight recovery	5 ppm by volume corrected to 8% oxygen	Continuous
		(b) cross recovery	25 ppm by volume corrected to 8% oxygen	
	Smelt dissolving tank	Particulate	0.2 lb/ton (0.1 g/kg	No requirement
		TRS	0.0168 lb/ton (0.0084 g/kg)	No requirement
	Lime kiln	Particulate (a) gaseous fuel	0.067 gr/dscf (0.15 g/dscm) corrected to 10% oxygen	No requirement
		(b) liquid fuel	0.13 gr/dscf (0.30 g/dscm) corrected to 10% oxygen	No requirement
		TRS	8 ppm by volume corrected to 10% oxygen	Continuous
	Digester, brown stack washer, evaporator, oxidation, or stripper systems	TRS	5 ppm by volume corrected to 10% oxygen*	Continuous
			*exceptions; see standards	Effluent gas incineration temperature; scrubber liquid supply pressure and gas stream pressure loss

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES (Continued)

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart DD - Grain Elevators				
Proposed/effective 8/3/78 (43 FR 34349)	Column and rack dryers	Opacity	0%	No requirement
Promulgated 8/3/78 (43 FR 34340)	Process equipment other than dryers	Particulate	0.01 gr/dscf (0.023 g/dscm)	No requirement
		Opacity	0%	No requirement
	Fugitive emissions: Truck unloading; railcar loading or unloading	Opacity	5%	No requirement
	Grain handling	Opacity	0%	No requirement
	Truck loading	Opacity	10%	No requirement
	Barge, ship loading	Opacity	20%	No requirement
Subpart HH - Lime Manufacturing Plants				
Proposed/effective 5/3/77 (42 FR 22506)	Rotary lime kiln	Particulate	0.30 lb/ton (0.15 kg/Mg	No requirement
		Opacity	10%	Continuous except when using wet scrubber
Promulgated 3/7/78 (43 FR 9452)	Lime hydrator	Particulate	0.15 lb/ton (0.075 kg/Mg)	No requirement
				Mass of feed to rotary lime kiln and hydrator

Title 40—PROTECTION OF ENVIRONMENT

Chapter I—Environmental Protection Agency

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES [1,1A]

Subpart A—General Provisions

Sec.
60.1 Applicability.
60.2 Definitions.
60.3 Abbreviations.
60.4 Address.
60.5 Determination of construction or modification.
60.6 Review of plans.
60.7 Notification and record keeping.
60.8 Performance tests.
60.9 Availability of information.
60.10 State authority.
60.11 Compliance with standards and maintenance requirements.[4]
60.12 Circumvention.[5]
60.13 Monitoring requirements.[18]
60.14 Modification.[22]
60.15 Reconstruction.[22]

Subpart B—Adoption and Submittal of State Plans for Designated Facilities [21]

Sec.
60.20 Applicability.
60.21 Definitions.
60.22 Publication of guideline documents, emission guidelines, and final compliance times.
60.23 Adoption and submittal of State plans; public hearings.
60.24 Emission standards and compliance schedules.
60.25 Emission inventories, source surveillance, reports.
60.26 Legal authority.
60.27 Actions by the Administrator.
60.28 Plan revisions by the State.
60.29 Plan revisions by the Administrator.

Subpart C—Emission Guidelines and Compliance Times [23]

Sec.
60.30 Scope.
60.31 Definitions.
60.32 Designated facilities.
60.33 Emission guidelines.
60.34 Compliance times.

Subpart D—Standards of Performance for Fossil-Fuel Fired Steam Generators

60.40 Applicability and designation of affected facility.
60.41 Definitions.
60.42 Standard for particulate matter.
60.43 Standard for sulfur dioxide.
60.44 Standard for nitrogen oxides.
60.45 Emission and fuel monitoring.
60.46 Test methods and procedures.

Subpart E—Standards of Performance for Incinerators

60.50 Applicability and designation of affected facility.
60.51 Definitions.
60.52 Standard for particulate matter.
60.53 Monitoring of operations.
60.54 Test methods and procedures.

Subpart F—Standards of Performance for Portland Cement Plants

60.60 Applicability and designation of affected facility.
60.61 Definitions.
60.62 Standard for particulate matter.
60.63 Monitoring of operations.
60.64 Test methods and procedures.

Subpart G—Standards of Performance for Nitric Acid Plants

60.70 Applicability and designation of affected facility.
60.71 Definitions.
60.72 Standard for nitrogen oxides.
60.73 Emission monitoring.
60.74 Test methods and procedures.

Subpart H—Standards of Performance for Sulfuric Acid Plants

60.80 Applicability and designation of affected facility.
60.81 Definitions.
60.82 Standard for sulfur dioxide.
60.83 Standard for acid mist.
60.84 Emission monitoring.
60.85 Test methods and procedures.

Subpart I—Standards of Performance for Asphalt Concrete Plants [5]

60.90 Applicability and designation of affected facility.
60.91 Definitions.
60.92 Standard for particulate matter.
60.93 Test methods and procedures.

Subpart J—Standards of Performance for Petroleum Refineries [5]

60.100 Applicability and designation of affected facility.
60.101 Definitions.
60.102 Standard for particulate matter.
60.103 Standard for carbon monoxide.
60.104 Standard for sulfur dioxide.
60.105 Emission monitoring.
60.106 Test methods and procedures.

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids [5]

60.110 Applicability and designation of affected facility.
60.111 Definitions.
60.112 Standard for hydrocarbons.
60.113 Monitoring of operations.

Subpart L—Standards of Performance for Secondary Lead Smelters [5]

Sec.
60.120 Applicability and designation of affected facility.
60.121 Definitions.
60.122 Standard for particulate matter.
60.123 Test methods and procedures.

Subpart M—Standards of Performance for Secondary Brass and Bronze Ingot Production Plants [5]

60.130 Applicability and designation of affected facility.
60.131 Definitions.
60.132 Standard for particulate matter.
60.133 Test methods and procedures.

Subpart N—Standards of Performance for Iron and Steel Plants [5]

60.140 Applicability and designation of affected facility.
60.141 Definitions.
60.142 Standard for particulate matter.
60.143 [Reserved]
60.144 Test methods and procedures.

Subpart O—Standards of Performance for Sewage Treatment Plants [5]

60.150 Applicability and designation of affected facility.
60.151 Definitions.
60.152 Standard for particulate matter.
60.153 Monitoring of operations.
60.154 Test methods and procedures.

Subpart P—Standards of Performance for Primary Copper Smelters [26]

60.160 Applicability and designation of affected facility.
60.161 Definitions.
60.162 Standard for particulate matter.
60.163 Standard for sulfur dioxide.
60.164 Standard for visible emissions.
60.165 Monitoring of operations.
60.166 Test methods and procedures.

Subpart Q—Standards of Performance for Primary Zinc Smelters [26]

60.170 Applicability and designation of affected facility.
60.171 Definitions.
60.172 Standard for particulate matter.
60.173 Standard for sulfur dioxide.
60.174 Standard for visible emissions.
60.175 Monitoring of operations.
60.176 Test methods and procedures.

Subpart R—Standards of Performance for Primary Lead Smelters [26]

60.180 Applicability and designation of affected facility.
60.181 Definitions.
60.182 Standard for particulate matter.
60.183 Standard for sulfur dioxide.
60.184 Standard for visible emissions.
60.185 Monitoring of operations.
60.186 Test methods and procedures.

Subpart S—Standards of Performance for Primary Aluminum Reduction Plants [27]

60.190 Applicability and designation of affected facility.
60.191 Definitions.
60.192 Standard for fluorides.
60.193 Standard for visible emissions.
60.194 Monitoring of operations.
60.195 Test methods and procedures.

Subpart T—Standards of Performance for the Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants [14]

60.200 Applicability and designation of affected facility.
60.201 Definitions.
60.202 Standard for fluorides.
60.203 Monitoring of operations.
60.204 Test methods and procedures.

Subpart U—Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants [14]

60.210 Applicability and designation of affected facility.
60.211 Definitions.
60.212 Standard for fluorides.
60.213 Monitoring of operations.
60.214 Test methods and procedures.

Subpart V—Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants [14]

60.220 Applicability and designation of affected facility.
60.221 Definitions.
60.222 Standard for fluorides.
60.223 Monitoring of operations.
60.224 Test methods and procedures.

Subpart W—Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants [14]

60.230 Applicability and designation of affected facility.
60.231 Definitions.
60.232 Standard for fluorides.
60.233 Monitoring of operations.
60.234 Test methods and procedures.

Subpart X—Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities [14]

60.240 Applicability and designation of affected facility.

60.241 Definitions.
60.242 Standard for fluorides.
60.243 Monitoring of operations.
60.244 Test methods and procedures.

Subpart Y—Standards of Performance for Coal Preparation Plants [26]

60.250 Applicability and designation of affected facility.
60.251 Definitions.
60.252 Standards for particulate matter.
60.253 Monitoring of operations.
60.254 Test methods and procedures.

Subpart Z—Standards of Performance for Ferroalloy Production Facilities [33]

60.260 Applicability and designation of affected facility.
60.261 Definitions.
60.262 Standard for particulate matter.
60.263 Standard for carbon monoxide.
60.264 Emission monitoring.
60.265 Monitoring of operations.
60.266 Test methods and procedures.

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces [16]

60.270 Applicability and designation of affected facility.
60.271 Definitions.
60.272 Standard for particulate matter.
60.273 Emission monitoring.
60.274 Monitoring of operations.
60.275 Test methods and procedures.

Subpart BB—Standards of Performance for Kraft Pulp Mills [82]

60.280 Applicability and designation of affected facility.
60.281 Definitions.
60.282 Standard for particulate matter.
60.283 Standard for total reduced sulfur (TRS).
60.284 Monitoring of emissions and operations.
60.285 Test methods and procedures.

Subpart DD—Standards of Performance for Grain Elevators [90]

Sec.
60.300 Applicability and designation of affected facility.
60.301 Definitions.
60.302 Standard for particulate matter.
60.303 Test methods and procedures.
60.304 Modification.

Subpart HH—Standards of Performance for Lime Manufacturing Plants [85]

Sec.
60.340 Applicability and designation of affected facility.
60.341 Definitions.
60.342 Standard for particulate matter.
60.343 Monitoring of emissions and operations.
60.344 Test methods and procedures.

Appendix A—Reference Methods [14]

Method 1—Sample and velocity traverses for stationary sources.
Method 2—Determination of stack gas velocity and volumetric flow rate (Type S pitot tube).
Method 3—Gas analysis for carbon dioxide, excess air, and dry molecular weight.
Method 4—Determination of moisture in stack gases.
Method 5—Determination of particulate emissions from stationary sources.
Method 6—Determination of sulfur dioxide emissions from stationary sources.
Method 7—Determination of nitrogen oxide emissions from stationary sources.
Method 8—Determination of sulfuric acid mist and sulfur dioxide emissions from stationary sources.
Method 9—Visual determination of the opacity of emissions from stationary sources.
Method 10—Determination of carbon monoxide emissions from stationary sources.[5]
Method 11—DETERMINATION OF HYDROGEN SULFIDE CONTENT OF FUEL GAS STREAMS IN PETROLEUM REFINERIES [79]
Method 12—[Reserved]
Method 13A—Determination of total fluoride emissions from stationary sources—SPADNS Zirconium Lake Method.
Method 13B—Determination of total fluoride emissions from stationary sources—Specific Ion Electrode Method.
Method 14—Determination of fluoride emissions from potroom roof monitors of primary aluminum plants.[27]

METHOD 15. DETERMINATION OF HYDROGEN SULFIDE, CARBONYL SULFIDE, AND CARBON DISULFIDE EMISSIONS FROM STATIONARY SOURCES [86]

METHOD- 16. SEMICONTINUOUS DETERMINATION OF SULFUR EMISSIONS FROM STATIONARY SOURCES [82]

METHOD 17. DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES (IN-STACK FILTRATION METHOD) [82]

Appendix B—Performance Specifications [18]

Performance Specification 1—Performance specifications and specification test procedures for transmissometer systems for continuous measurement of the opacity of stack emissions.

Performance Specification 2—Performance specifications and specification test procedures for monitors of SO_2 and NO_x from stationary sources.

Performance Specification 3—Performance specifications and specification test procedures for monitors of CO_2 and O_2 from stationary sources.

Appendix C—Determination of Emission Rate Change [22]

Appendix D—Required Emission Inventory Information [21]

AUTHORITY: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), unless otherwise noted.[68,83]

Subpart A—General Provisions

§ 60.1 Applicability.[8,21]

Except as provided in Subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

§ 60.2 Definitions.

As used in this part, all terms not defined herein shall have the meaning given them in the Act:

(a) "Act" means the Clean Air Act (42 U.S.C. 1857 et seq., as amended by Public Law 91–604, 84 Stat. 1676).

(b) "Administrator" means the Administrator of the Environmental Protection Agency or his authorized representative.

(c) "Standard" means a standard of performance proposed or promulgated under this part.

(d) "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant and which contains any one or combination of the following:

(1) Affected facilities.

(2) Existing facilities.

(3) Facilities of the type for which no standards have been promulgated in this part.[22]

(e) "Affected facility" means, with reference to a stationary source, any apparatus to which a standard is applicable.

(f) "Owner or operator" means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

(g) "Construction" means fabrication, erection, or installation of an affected facility.

(h) "Modification" means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.[22]

(i) "Commenced" means, with respect to the definition of "new source" in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.[5]

(j) "Opacity" means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

(k) "Nitrogen oxides" means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

(l) "Standard conditions" means a temperature of 293 K (68° F) and a pressure of 101.3 kilopascals (29.92 in Hg).[5,84]

(m) "Proportional sampling" means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

(n) "Isokinetic sampling" means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

(o) "Startup" means the setting in operation of an affected facility for any purpose.

(p) "Shutdown" means the cessation of operation of an affected facility for any purpose.[4]

(q) "Malfunction" means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.[4]

(r) "One-hour period" means any 60 minute period commencing on the hour.[18]

(s) "Reference method" means any method of sampling and analyzing for an air pollutant as described in Appendix A to this part.[5,8]

(t) "Equivalent method" means any method of sampling and analyzing for an air pollutant which have been demonstrated to the Adminstartor's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.[5]

(u) "Alternative method" means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.[5]

(v) "Particulate matter" means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.[5,8,90]

(w) "Run" means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.[5]

(x) "Six-minute period" means any one of the 10 equal parts of a one-hour period.[18]

(y) "Continuous monitoring system" means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.[18]

(z) "Monitoring device" means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.[18]

(aa) "Existing facility" means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.[22]

(bb) "Capital expenditure" means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code.[22]

§ 60.3 Units and abbreviations.[5,62]

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere
g—gram
Hz—hertz
J—joule
K—degree Kelvin
kg—kilogram
m—meter
m^3—cubic meter
mg—milligram—10^{-3} gram
mm—millimeter—10^{-3} meter
Mg—megagram—10^{6} gram
mol—mole
N—newton
ng—nanogram—10^{-9} gram
nm—nanometer—10^{-9} meter
Pa—pascal
s—second
V—volt
W—watt
Ω—ohm
μg—microgram—10^{-6} gram[65]

(b) Other units of measure:

Btu—British thermal unit
°C—degree Celsius (centigrade)
cal—calorie
cfm—cubic feet per minute
cu ft—cubic feet
dcf—dry cubic feet
dcm—dry cubic meter
dscf—dry cubic feet at standard conditions
dscm—dry cubic meter at standard conditions
eq—equivalent
°F—degree Fahrenheit
ft—feet
gal—gallon
gr—grain
g-eq—gram equivalent
hr—hour
in—inch
k—1,000
l—liter
lpm—liter per minute
lb—pound
meq—milliequivalent
min—minute
ml—milliliter

mol. wt.—molecular weight
ppb—parts per billion
ppm—parts per million
psia—pounds per square inch absolute
psig—pounds per square inch gage
°R—degree Rankine
scf—cubic feet at standard conditions
scfh—cubic feet per hour at standard conditions
scm—cubic meter at standard conditions
sec—second
sq ft—square feet
std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide
CO—carbon monoxide
CO_2—carbon dioxide
HCl—hydrochloric acid
Hg—mercury
H_2O—water
H_2S—hydrogen sulfide
H_2SO_4—sulfuric acid
N_2—nitrogen
NO—nitric oxide
NO_2—nitrogen dioxide
NO_x—nitrogen oxides
O_2—oxygen
SO_2—sulfur dioxide
SO_3—sulfur trioxide
SO_x—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

(Sections 111 and 301(a) of the Clean Air Act; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a)).)

§ 60.4 Address.[5,12]

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate and addressed to the appropriate Regional Office of the Environmental Protection Agency, to the attention of the Director, Enforcement Division. The regional offices are as follows:

Region I (Connecticut, Maine, New Hampshire, Massachusetts, Rhode Island, Vermont), John F. Kennedy Federal Building, Boston, Massachusetts 02203.

Region II (New York, New Jersey, Puerto Rico, Virgin Islands), Federal Office Building, 26 Federal Plaza (Foley Square), New York, N.Y. 10007.

Region III (Delaware, District of Columbia, Pennsylvania, Maryland, Virginia, West Virginia), Curtis Building, Sixth and Walnut Streets, Philadelphia, Pennsylvania 19106.

Region IV (Alabama, Florida, Georgia, Mississippi, Kentucky, North Carolina, South Carolina, Tennessee), Suite 300, 1421 Peachtree Street, Atlanta, Georgia 30309.

Region V (Illinois, Indiana, Minnesota, Michigan, Ohio, Wisconsin), 230 South Dearborn Street, Chicago, Illinois 60604.[59]

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas), 1600 Patterson Street, Dallas, Texas 75201.

Region VII (Iowa, Kansas, Missouri, Nebraska), 1735 Baltimore Street, Kansas City, Missouri 63108.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming), 196 Lincoln Towers, 1860 Lincoln Street, Denver, Colorado 80203.

Region IX (Arizona, California, Hawaii, Nevada, Guam, American Samoa), 100 California Street, San Francisco, California 94111

Region X (Washington, Oregon, Idaho, Alaska), 1200 Sixth Avenue, Seattle, Washington 98101.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(A) [reserved].

(B) State of Alabama, Air Pollution Control Division, Air Pollution Control Commission, 645 S. McDonough Street, Montgomery, Alabama 36104 [45]

(C) [reserved].

(D) Arizona.

Maricopa County Department of Health Services, Bureau of Air Pollution Control, 1825 East Roosevelt Street, Phoenix, Ariz. 85006.

Pima County Health Department, Air Quality Control District, 151 West Congress, Tucson, Ariz. 85701.[51,89]

(F) California.

Bay Area Air Pollution Control District, 939 Ellis Street, San Francisco, Calif. 94109.

Del Norte County Air Pollution Control District, Courthouse, Crescent City, Calif. 95531.

Fresno County Air Pollution Control District, 515 South Cedar Avenue, Fresno, Calif. 93702

Humboldt County Air Pollution Control District, 5600 South Broadway, Eureka, Calif. 95501.

Kern County Air Pollution Control District, 1700 Flower Street (P.O. Box 997), Bakersfield, Calif. 93302.

Madera County Air Pollution Control District, 135 West Yosemite Avenue, Madera, Calif. 93637.

Mendocino County Air Pollution Control District, County Courthouse, Ukiah, Calif. 94582.

Monterey Bay Unified Air Pollution Control District, 420 Church Street (P.O. Box 487), Salinas, Calif. 93901.

Northern Sonoma County Air Pollution Control District, 3313 Chanate Road, Santa Rosa, Calif. 95404.

Sacramento County Air Pollution Control District, 3701 Branch Center Road, Sacramento, Calif. 95827.

San Diego County Air Pollution Control District, 9150 Chesapeake Drive, San Diego, Calif. 92123.

San Joaquin County Air Pollution Control District, 1601 East Hazelton Street (P.O. Box 2009), Stockton, Calif. 95201.

Santa Barbara County Air Pollution Control District, 4440 Calle Real, Santa Barbara, Calif. 93110.

Shasta County Air Pollution Control District, 1855 Placer Street, Redding, Calif. 96001.

South Coast Air Quality Management District, 9420 Telstar Avenue, El Monte, Calif. 91731.

Stanislaus County Air Pollution Control District, 820 Scenic Drive, Modesto, Calif. 95350.

Trinity County Air Pollution Control District, Box AJ, Weaverville, Calif. 96093.

Ventura County Air Pollution Control District, 625 East Santa Clara Street, Ventura, Calif. 93001.[15,17,36,40,44,48,52,89]

(G)—State of Colorado, Colorado Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.[20]

(H) State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.[31]

(I) State of Delaware (for fossil fuel-fired steam generators; incinerators; nitric acid plants; asphalt concrete plants; storage vessels for petroleum liquids; and sewage treatment plants only): Delaware Department of Natural Resources and Environmental Control, Edward Tatnall Building, Dover, Del. 19901.[81]

(J)-(K) [reserved]

(L) State of Georgia, Environmental Protection Division, Department of Natural Resources, 270 Washington Street, S.W., Atlanta, Georgia 30334.[38]

(M) [Reserved]

(N) State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.[13]

(O) [Reserved]

(P) State of Indiana, Indiana Air Pollution Control Board, 1330 West Michigan Street, Indianapolis, Indiana 46206.[46]

(Q) State of Iowa, Department of Environmental Quality, 3920 Delaware, P.O. Box 3226, Des Moines, Iowa 50316.[54]

(R)- [reserved].

(S) Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Ky. 40601.[80]

(T) [Reserved]

(U) State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.[24]

(V) [Reserved]

(W) Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, 600 Washington Street, Boston, Massachusetts 02111.[34]

(X) State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th Floor, Lansing, Michigan 48926.[25]

(Y) Minnesota Pollution Control Agency, Division of Air Quality, 1935 West County Road B-2, Roseville, Minn. 55113.[78]

(Z) [Reserved]

(AA) [reserved]

(BB) State of Montana, Department of Health and Environmental Services, Cogswell Building, Helena, Mont. 59601.[70]

(CC) Nebraska Department of Environmental Control, P.O. Box 94653, State House Station, Lincoln, Nebraska 68509.[34]

(DD) Nevada.

Clark County, County District Health Department, Air Pollution Control Division, 625 Shadow Lane, Las Vegas, Nev. 89106.

Washoe County District Health Department, Division of Environmental Protection, 10 Kirman Avenue, Reno, Nev. 89502.[89]

(EE) New Hampshire Air Pollution Control Agency, Department of Health and Welfare, State Laboratory Building, Hazen Drive, Concord, New Hampshire 03301.[34]

(FF)—State of New Jersey: New Jersey Department of Environmental Protection, John Fitch Plaza, P.O. Box 2807, Trenton, New Jersey 08625.[63]

(GG) [reserved].

(HH)—New York: New York State Department of Environmental Conservation, 50 Wolf Road, New York 12233, attention: Division of Air Resources.[19]

(II) North Carolina Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, P.O. Box 27687, Raleigh, North Carolina 27611. Attention: Air Quality Section.[34]

(JJ)—State of North Dakota, State Department of Health, State Capitol, Bismarck, North Dakota 58501.[47]

(KK) Ohio—

Medina, Summit and Portage Counties; Director, Air Pollution Control, 177 South Broadway, Akron, Ohio, 44308.

Stark County; Director, Air Pollution Control Division, Canton City Health Department, City Hall, 218 Cleveland Avenue SW, Canton, Ohio, 44702.

Butler, Clermont, Hamilton and Warren Counties; Superintendent, Division of Air Pollution Control, 2400 Beekman Street, Cincinnati, Ohio, 45214.

Cuyahoga County; Commissioner, Division of Air Pollution Control, Department of Public Health and Welfare, 2735 Broadway Avenue, Cleveland, Ohio, 44115.

Lorain County; Control Officer, Division of Air Pollution Control, 200 West Erie Avenue, 7th Floor, Lorain, Ohio, 44052.

Belmont, Carroll, Columbiana, Harrison, Jefferson, and Monroe Counties; Director, North Ohio Valley Air Authority (NOVAA), 814 Adams Street, Steubenville, Ohio, 43952.

Clark, Darke, Greene, Miami, Montgomery, and Preble Counties; Supervisor, Regional Air Pollution Control Agency (RAPCA), Montgomery County Health Department, 451 West Third Street, Dayton, Ohio, 45402.

Lucas County and the City of Rossford (in Wood County); Director, Toledo Pollution Control Agency, 26 Main Street, Toledo, Ohio, 43606.

Adams, Brown, Lawrence, and Scioto Counties; Engineer-Director, Air Division, Portsmouth City Health Department, 740 Second Street, Portsmouth, Ohio, 45662.

Allen, Ashland, Auglaize, Crawford, Defiance, Erie, Fulton, Hancock, Hardin, Henry, Huron, Knox, Marion, Mercer, Morrow, Ottawa, Paulding, Putnam, Richland, Sandusky, Seneca, Van Wert, Williams, Wood (except City of Rossford), and Wyandot Counties; Ohio Environmental Protection Agency, Northwest District Office, 111 West Washington Street, Bowling Green, Ohio, 43402.

Ashtabula, Geauga, Lake, Mahoning, Trumbull, and Wayne Counties; Ohio Environmental Protection Agency, Northeast District Office, 2110 East Aurora Road, Twinsburg, Ohio, 44087.

Athens, Coshocton, Gallia, Guernsey, Highland, Hocking, Holmes, Jackson, Meigs, Morgan, Muskingum, Noble, Perry, Pike, Ross, Tuscarawas, Vinton, and Washington Counties; Ohio Environmental Protection Agency, Southeast District Office, Route 3, Box 603, Logan, Ohio, 43138.

Champaign, Clinton, Logan, and Shelby Counties; Ohio Environmental Protection Agency, Southwest District Office, 7 East Fourth Street, Dayton, Ohio, 45402.

Delaware, Fairfield, Fayette, Franklin, Licking, Madison, Pickaway, and Union Counties; Ohio Environmental Protection Agency, Central District Office, 360 East Broad Street, Columbus, Ohio, 43215.[53]

(LL) [reserved].

(MM)—State of Oregon, Department of Environmental Quality, 1234 SW Morrison Street, Portland, Oregon 97205.[29]

(NN) (a) City of Philadelphia: Philadelphia Department of Public Health, Air Management Services, 801 Arch Street, Philadelphia, Pennsylvania 19107.[38]

(OO) State of Rhode Island, Department of Environmental Management, 83 Park Street, Providence, R.I. 02908[92]

(PP) State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.[36]

(QQ) State of South Dakota, Department of Environmental Protection, Joe Foss Building, Pierre, South Dakota 57501.[32]

(RR), (SS) [reserved].

(TT)—State of Utah, Utah Air Conservation Committee, State Division of Health, 44 Medical Drive, Salt Lake City, Utah 84113.[37]

(UU)—State of Vermont, Agency of Environmental Protection, Box 489, Montpelier, Vermont 05602.[33]

(VV) Commonwealth of Virginia, Virginia State Air Pollution Control Board Room 1106, Ninth Street Office Building Richmond, Virginia 23219.[30]

(WW) (i) Washington: State of Washington, Department of Ecology, Olympia, Washington 98504.

(ii) Northwest Air Pollution Authority, 207 Pioneer Building, Second and Pine Streets, Mount Vernon, Washington 98273.

(iii) Puget Sound Air Pollution Control Agency, 410 West Harrison Street, Seattle, Washington 98119.

(iv) Spokane County Air Pollution Control Authority, North 811 Jefferson, Spokane, Washington 99201.

(v) Southwest Air Pollution Control Authority, Suite 7601 H, NE Hazel Dell Avenue, Vancouver, Washington 98665.[12,26]

(XX) [reserved].

(YY) Wisconsin—

Wisconsin Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.[3]

(ZZ) State of Wyoming, Air Quality Division of the Department of Environmental Quality, Hathaway Building, Cheyenne, Wyo. 82002.[72]

(AAA) [reserved].

(BBB)—Commonwealth of Puerto Rico Commonwealth of Puerto Rico Environmental Quality Board, P.O. Box 11785, Santurce, P.R. 00910[77]

(CCC)—U.S. Virgin Islands: U.S. Virgin Islands Department of Conservation and Cultural Affairs, P.O. Box 578, Charlotte Amalie, St. Thomas, U.S. Virgin Islands 00801.[41]

(DDD) [reserved].

§ 60.5 Determination of construction or modification.[22]

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

§ 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b) (1) A separate request shall be submitted for each construction or modification project.[5]

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any requipment to be used for measurement or control of emissions.[5]

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

§ 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.[22]

(2) A notification of the anticipated date of initial startup of an affected facility postmarked not more than 60 days nor less than 30 days prior to such date.[22]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.[22]

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable

subpart or in § 60.14(e) and the exemption is not denied under § 60.14(d)(4). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.[22]

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with § 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.[18]

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.[18]

(c) Each owner or operator required to install a continuous monitoring system shall submit a written report of excess emissions (as defined in applicable subparts) to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter and shall include the following information:[18]

(1) The magnitude of excess emissions computed in accordance with § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.[18]

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.[18]

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.[18]

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.[4, 18]

(d) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records.[5, 18]

(e) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.[22]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, or (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.[5]

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.[4, 74]

(d) The owner or operator of an affected facility shall provide the Administrator 30 days prior notice of the performance test to afford the Administrator the opportunity to have an observer present.[5]

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.[5]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.9 Availability of information.

The availabality to the public of information provided to, or otherwise obtained by, the Administrator under this Part shall be governed by Part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by § 2.201 through § 2.213 of this chapter and not by § 2.301 of this chapter.)

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

(Sec. 116 of the Clean Air Act as amended (42 U.S.C. 7416)).[68, 83]

§ 60.11 Compliance with standards and maintenance requirements.[4]

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by § 60.8.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of this part or any alternative method that is approved by the Administrator. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in Appendix B of this part, has been properly maintained and (at the time of the alleged violation) calibrated, and that the resulting data have not been tampered with in any way.[10,60]

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e) (1) An owner or operator of an affected facility may request the Administrator to determine opacity of emissions from the affected facility during the initial performance tests required by § 60.8.[10]

(2) Upon receipt from such owner or operator of the written report of the results of the performance tests required by § 60.8, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with § 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.[10]

(3) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.[10]

(4) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the FEDERAL REGISTER.[10]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.12 Circumvention.[5]

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

§ 60.13 Monitoring requirements.[18]

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring system under Appendix B to this part, unless:[82]

(1) The continuous monitoring system is subject to the provisions of paragraphs (c)(2) and (c)(3) of this section, or[82]

(2) otherwise specified in an applicable subpart or by the Administrator.[82]

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under § 60.8. Verification of operational status shall, as a minimum, consist of the following:

(1) For continuous monitoring systems referenced in paragraph (c) (1) of this section, completion of the conditioning period specified by applicable requirements in Appendix B.

(2) For continuous monitoring systems referenced in paragraph (c) (2) of this section, completion of seven days of operation.

(3) For monitoring devices referenced in applicable subparts, completion of the manufacturer's written requirements or recommendations for checking the operation or calibration of the device.

(c) During any performance tests required under § 60.8 or within 30 days thereafter and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of any affected facility shall conduct continuous monitoring system performance evaluations and furnish the Administrator within 60 days thereof two or, upon request, more copies of a written report of the results of such tests. These continuous monitoring system performance evaluations shall be conducted in accordance with the following specifications and procedures:

(1) Continuous monitoring systems listed within this paragraph except as provided in paragraph (c) (2) of this section shall be evaluated in accordance with the requirements and procedures contained in the applicable performance specification of Appendix B as follows:

(i) Continuous monitoring systems for measuring opacity of emissions shall comply with Performance Specification 1.

(ii) Continuous monitoring systems for measuring nitrogen oxides emissions shall comply with Performance Specification 2.

(iii) Continuous monitoring systems for measuring sulfur dioxide emissions shall comply with Performance Specification 2.

(iv) Continuous monitoring systems for measuring the oxygen content or carbon dioxide content of effluent gases shall comply with Performance Specification 3.

(2) An owner or operator who, prior to September 11, 1974, entered into a binding contractual obligation to purchase specific continuous monitoring system components except as referenced by paragraph (c) (2) (iii) of this section shall comply with the following requirements:

(i) Continuous monitoring systems for measuring opacity of emissions shall be capable of measuring emission levels within ±20 percent with a confidence level of 95 percent. The Calibration Error Test and associated calculation procedures set forth in Performance Specification 1 of Appendix B shall be used for demonstrating compliance with this specification.

(ii) Continuous monitoring systems for measurement of nitrogen oxides or sulfur dioxide shall be capable of measuring emission levels within ±20 percent with a confidence level of 95 percent. The Calibration Error Test, the Field Test for Accuracy (Relative), and associated operating and calculation procedures set forth in Performance Specification 2 of Appendix B shall be used for demonstrating compliance with this specification.

(iii) Owners or operators of all continuous monitoring systems installed on an affected facility prior to October 6, 1975 are not required to conduct tests under paragraphs (c) (2) (i) and/or (ii) of this section unless requested by the Administrator.[23]

(3) All continuous monitoring systems referenced by paragraph (c) (2) of this section shall be upgraded or replaced (if necessary) with new continuous monitoring systems, and the new or improved systems shall be demonstrated to comply with applicable performance specifications under paragraph (c) (1) of this section on or before September 11, 1979.[37]

(d) Owners or operators of all continuous monitoring systems installed in accordance with the provisions of this part shall check the zero and span drift

at least once daily in accordance with the method prescribed by the manufacturer of such systems unless the manufacturer recommends adjustments at shorter intervals, in which case such recommendations shall be followed. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour calibration drift limits of the applicable performance specifications in Appendix B are exceeded. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero or span drift adjustments except that for systems using automatic zero adjustments, the optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds four percent opacity. Unless otherwise approved by the Administrator, the following procedures, as applicable, shall be followed:

(1) For extractive continuous monitoring systems measuring gases, minimum procedures shall include introducing applicable zero and span gas mixtures into the measurement system as near the probe as is practical. Span and zero gases certified by their manufacturer to be traceable to National Bureau of Standards reference gases shall be used whenever these reference gases are available. The span and zero gas mixtures shall be the same composition as specified in Appendix B of this part. Every six months from date of manufacture, span and zero gases shall be reanalyzed by conducting triplicate analyses with Reference Methods 6 for SO_2, 7 for NO_x, and 3 for O_2 and CO_2, respectively. The gases may be analyzed at less frequent intervals if longer shelf lives are guaranteed by the manufacturer.

(2) For non-extractive continuous monitoring systems measuring gases, minimum procedures shall include upscale check(s) using a certified calibration gas cell or test cell which is functionally equivalent to a known gas concentration. The zero check may be performed by computing the zero value from upscale measurements or by mechanically producing a zero condition.

(3) For continuous monitoring systems measuring opacity of emissions, minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraphs (c)(1) and (c)(2) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive ten-second period and one cycle of data recording for each successive six-minute period.[57]

(2) All continuous monitoring systems referenced by paragraph (c)(1) of this section for measuring oxides of nitrogen, sulfur dioxide, carbon dioxide, or oxygen shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(3) All continuous monitoring systems referenced by paragraph (c)(2) of this section, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive one-hour period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install applicable continuous monitoring systems on each separate effluent unless the installation of fewer systems is approved by the Administrator.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to six-minute averages and for systems other than opacity to one-hour averages for time periods under § 60.2 (x) and (r) respectively. Six-minute opacity averages sha'l be calculated from 24 or more data points equally spaced over each six-minute period. For systems other than opacity, one-hour averages shall be computed from four or more data points equally spaced over each one-hour period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data output of all continuous monitoring systems may be recorded in reduced or nonreduced form (e.g. ppm pollutant and percent O_2 or lb/million Btu of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in subparts to specify the applicable standard (e.g., rounded to the nearest one percent opacity).

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:[42]

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances with the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, Appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities are released to the atmosphere through more than one point.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[64, 83]

§ 60.14 Modification.[22]

(a) Except as provided under paragraphs (d), (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b) (1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in Appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) A modification shall not be deemed to occur if an existing facility undergoes a physical or operational change where the owner or operator demonstrates to the Administrator's satisfaction (by any of the procedures prescribed under paragraph (b) of this section) that the total emission rate of any pollutant has not increased from all facilities within the stationary source to which appropriate reference, equivalent, or alternative methods, as defined in § 60.2 (s), (t) and (u), can be applied. An owner or operator may completely and permanently close any facility within a stationary source to prevent an increase in the total emission rate regardless of whether such reference, equivalent or alternative method can be applied, if the decrease in emission rate from such closure can be adequately determined by any of the procedures prescribed under paragraph (b) of this section. The owner or operator of the source shall have the burden of demonstrating compliance with this section.

(1) Such demonstration shall be in writing and shall include: (i) The name and address of the owner or operator.

(ii) The location of the stationary source.

(iii) A complete description of the existing facility undergoing the physical or operational change resulting in an increase in emission rate, any applicable control system, and the physical or operational change to such facility.

(iv) The emission rates into the atmosphere from the existing facility of each pollutant to which a standard applies determined before and after the physical or operational change takes place, to the extent such information is known or can be predicted.

(v) A complete description of each facility and the control systems, if any, for those facilities within the stationary source where the emission rate of each pollutant in question will be decreased to compensate for the increase in emission rate from the existing facility undergoing the physical or operational change.

(vi) The emission rates into the atmosphere of the pollutants in question from each facility described under paragraph (d)(1)(v) of this section both before and after the improvement or installation of any applicable control system or any physical or operational changes to such facilities to reduce emission rate.

(vii) A complete description of the procedures and methods used to determine the emission rates.

(2) Compliance with paragraph (d) of this section may be demonstrated by the methods listed in paragraph (b) of this section, where appropriate. Decreases in emissions resulting from requirements of a State implementation plan approved or promulgated under Part 52 of this chapter will not be acceptable. The required reduction in emission rate may be accomplished through the installation or improvement of a control system or through physical or operational changes to facilities including reducing the production of a facility or closing a facility.

(3) Emission rates established for the existing facility which is undergoing a physical or operational change resulting in an increase in the emission rate, and established for the facilities described under paragraph (d)(1)(v) of this section shall become the baseline for determining whether such facilities undergo a modification or are in compliance with standards.

(4) Any emission rate in excess of that rate established under paragraph (d)(3) of this section shall be a violation of these regulations except as otherwise provided in paragraph (e) of this section. However, any owner or operator electing to demonstrate compliance under this paragraph (d) must apply to the Administrator to obtain the use of any exemptions under paragraphs (e) (2), (e)(3), and (e)(4) of this section. The Administrator will grant such exemption only if, in his judgment, the compliance originally demonstrated under this paragraph will not be circumvented or nullified by the utilization of the exemption.

(5) The Administrator may require the use of continuous monitoring devices and compliance with necessary reporting procedures for each facility described in paragraph (d)(1)(iii) and (d)(1)(v) of this section.

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility. 90

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 119(d)(5) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraphs (a) or (d) of this section, compliance with all applicable standards must be achieved.

§ 60.15 Reconstruction.[22]

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

Subpart B—Adoption and Submittal of State Plans for Designated Facilities [21]

§ 60.20 Applicability.

The provisions of this subpart apply to States upon publication of a final guideline document under § 60.22(a).

§ 60.21 Definitions.

Terms used but not defined in this subpart shall have the meaning given them in the Act and in subpart A:

(a) "Designated pollutant" means any air pollutant, emissions of which are subject to a standard of performance for new stationary sources but for which air quality criteria have not been issued, and which is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

(b) "Designated facility" means any existing facility (see § 60.2(aa)) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2(e)).

(c) "Plan" means a plan under section 111(d) of the Act which establishes emission standards for designated pollutants from designated facilities and provides for the implementation and enforcement of such emission standards.

(d) "Applicable plan" means the plan, or most recent revision thereof, which has been approved under § 60.27(b) or promulgated under § 60.27(d).

(e) "Emission guideline" means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities.

(f) "Emission standard" means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, or prescribing equipment specifications for control of air pollution emissions.

(g) "Compliance schedule" means a legally anforceable schedule specifying a date or dates by which a source or category or sources must comply with specific emission standards contained in a plan or with any increments of progress to achieve such compliance.

(h) "Increments of progress" means steps to achieve compliance which must be taken by an owner or operator of a designated facility, including:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(3) Initiation of on-site construction or installation of emission control equipment or process change;

(4) Completion of on-site construction or installation of emission control equipment or process change; and

(5) Final compliance.

(i) "Region" means an air quality control region designated under section 107 of the Act and described in Part 81 of this chapter.

(j) "Local agency" means any local governmental agency.

§ 60.22 Publication of guideline documents, emission guidelines, and final compliance times.

(a) After promulgation of a standard of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information pertinent to control of the designated pollutant from designated facilities. Notice of the availability of the draft guideline document will be published in the Federal Register, and public comments on its contents will be invited. After consideration of public comments, a final guideline document will be published and notice of its availability will be published in the Federal Register.

(b) Guideline documents published under this section will provide information for the development of State plans, such as:

(1) Information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.

(2) A description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.

(3) Information on the degree of emission reduction which is achievable with each system, together with information on the costs and environmental effects of applying each system to designated facilities.

(4) Incremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.

(5) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

(6) Such other available information as the Administrator determines may contribute to the formulation of State plans.

(c) Except as provided in paragraph (d)(1) of this section, the emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in Subpart C of this part with such modifications as may be appropriate.

(d)(1) If the Administrator determines that a designated pollutant may cause or contribute to endangerment of public welfare, but that adverse effects on public health have not been demonstrated, he will include the determination in the draft guideline document and in the Federal Register notice of its availability. Except as provided in paragraph (d)(2) of this section, paragraph (c) of this section shall be inapplicable in such cases.

(2) If the Administrator determines at any time on the basis of new information that a prior determination under paragraph (d)(1) of this section is incorrect or no longer correct, he will publish notice of the determination in the Federal Register, revise the guideline document as necessary under paragraph (a) of this section, and propose and promulgate emission guidelines and compliance times under paragraph (c) of this section.

§ 60.23 Adoption and submittal of State plans; public hearings.

(a)(1) Within nine months after notice of the availability of a final guideline document is published under § 60.22(a), each State shall adopt and submit to the Administrator, in accordance with § 60.4, a plan for the control of the designated pollutant to which the guideline document applies.

(2) Within nine months after notice of the availability of a final revised guideline document is published as provided in § 60.22(d)(2), each State shall adopt and submit to the Administrator any plan revision necessary to meet the requirements of this subpart.

(b) If no designated facility is located within a State, the State shall submit a letter of certification to that effect to the Administrator within the time specified in paragraph (a) of this section. Such certification shall exempt the State from the requirements of this subpart for that designated pollutant.

(c)(1) Except as provided in paragraphs (c)(2) and (c)(3) of this section, the State shall, prior to the adoption of any plan or revision thereof, conduct one or more public hearings within the State on such plan or plan revision.

(2) No hearing shall be required for any change to an increment of progress in an approved compliance schedule unless the change is likely to cause the facility to be unable to comply with the final compliance date in the schedule.

(3) No hearing shall be required on an emission standard in effect prior to the effective date of this subpart if it was adopted after a public hearing and is at least as stringent as the corresponding emission guideline specified in the applicable guideline document published under § 60.22(a).

(d) Any hearing required by paragraph (c) of this section shall be held only after reasonable notice. Notice shall be given at least 30 days prior to the date of such hearing and shall include:

(1) Notification to the public by prominently advertising the date, time, and place of such hearing in each region affected;

(2) Availability, at the time of public announcement, of each proposed plan or

revision thereof for public inspection in at least one location in each region to which it will apply;

(3) Notification to the Administrator;

(4) Notification to each local air pollution control agency in each region to which the plan or revision will apply; and

(5) In the case of an interstate region, notification to any other State included in the region.

(e) The State shall prepare and retain, for a minimum of 2 years, a record of each hearing for inspection by any interested party. The record shall contain, as a minimum, a list of witnesses together with the text of each presentation.

(f) The State shall submit with the plan or revision:

(1) Certification that each hearing required by paragraph (c) of this section was held in accordance with the notice required by paragraph (d) of this section; and

(2) A list of witnesses and their organizational affiliations, if any, appearing at the hearing and a brief written summary of each presentation or written submission.

(g) Upon written application by a State agency (through the appropriate Regional Office), the Administrator may approve State procedures designed to insure public participation in the matters for which hearings are required and public notification of the opportunity to participate if, in the judgment of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and participation of the public. The Administrator may impose such conditions on his approval as he deems necessary. Procedures approved under this section shall be deemed to satisfy the requirements of this subpart regarding procedures for public hearings.

§ 60.24 Emission standards and compliance schedules.

(a) Each plan shall include emission standards and compliance schedules.

(b)(1) Emission standards shall prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

(2) Test methods and procedures for determining compliance with the emission standards shall be specified in the plan. Methods other than those specified in Appendix A to this part may be specified in the plan if shown to be equivalent or alternative methods as defined in § 60.2 (t) and (u).

(3) Emission standards shall apply to all designated facilities within the State. A plan may contain emission standards adopted by local jurisdictions provided that the standards are enforceable by the State.

(c) Except as provided in paragraph (f) of this section, where the Administrator has determined that a designated pollutant may cause or contribute to endangerment of public health, emission standards shall be no less stringent than the corresponding emission guideline(s) specified in Subpart C of this part, and final compliance shall be required as expeditiously as practicable but no later than the compliance times specified in Subpart C of this part.

(d) Where the Administrator has determined that a designated pollutant may cause or contribute to endangerment of public welfare but that adverse effects on public health have not been demonstrated, States may balance the emission guidelines, compliance times, and other information provided in the applicable guideline document against other factors of public concern in establishing emission standards, compliance schedules, and variances. Appropriate consideration shall be given to the factors specified in § 60.22(b) and to information presented at the public hearing(s) conducted under § 60.23(c).

(e) (1) Any compliance schedule extending more than 12 months from the date required for submittal of the plan shall include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Increments of progress shall include, where practicable, each increment of progress specified in § 60.21(h) and shall include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance.

(2) A plan may provide that compliance schedules for individual sources or categories of sources will be formulated after plan submittal. Any such schedule shall be the subject of a public hearing held according to § 60.23 and shall be submitted to the Administrator within 60 days after the date of adoption of the schedule but in no case later than the date prescribed for submittal of the first semiannual report required by § 60.25(e).

(f) On a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

(g) Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing (1) emission standards more stringent than emission guidelines specified in Subpart C of this part or in applicable guideline documents or (2) compliance schedules requiring final compliance at earlier times than those specified in Subpart C or in applicable guideline documents.

(Sec. 116 of the Clean Air Act as amended (42 U.S.C. 7416)).[68, 83]

§ 60.25 Emission inventories, source surveillance, reports.

(a) Each plan shall include an inventory of all designated facilities, including emission data for the designated pollutants and information related to emissions as specified in Appendix D to this part. Such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable emission standards. As used in this subpart, "correlated" means presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions allowable under applicable emission standards.

(b) Each plan shall provide for monitoring the status of compliance with applicable emission standards. Each plan shall, as a minimum, provide for:

(1) Legally enforceable procedures for requiring owners or operators of designated facilities to maintain records and periodically report to the State information on the nature and amount of emissions from such facilities, and/or such other information as may be necessary to enable the State to determine whether such facilities are in compliance with applicable portions of the plan.

(2) Periodic inspection and, when applicable, testing of designated facilities.

(c) Each plan shall provide that information obtained by the State under paragraph (b) of this section shall be correlated with applicable emission standards (see § 60.25(a)) and made available to the general public.

(d) The provisions referred to in paragraphs (b) and (c) of this section shall be specifically identified. Copies of such provisions shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates:

(i) That the provisions are applicable to the designated pollutant(s) for which the plan is submitted, and

(ii) That the requirements of § 60.26 are met.

(e) The State shall submit reports on progress in plan enforcement to the Administrator on a semiannual basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. The semiannual periods are January 1–June 30 and July 1–December 31. Information required under this paragraph shall be included in the semiannual reports required by § 51.7 of this chapter.

(f) Each progress report shall include:

(1) Enforcement actions initiated against designated facilities during the reporting period, under any emission

standard or compliance schedule of the plan.

(2) Identification of the achievement of any increment of progress required by the applicable plan during the reporting period.

(3) Identification of designated facilities that have ceased operation during the reporting period.

(4) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of plan development but began operation during the reporting period.

(5) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(6) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

§ 60.26 Legal authority.

(a) Each plan shall show that the State has legal authority to carry out the plan, including authority to:

(1) Adopt emission standards and compliance schedules applicable to designated facilities.

(2) Enforce applicable laws, regulations, standards, and compliance schedules, and seek injunctive relief.

(3) Obtain information necessary to determine whether designated facilities are in compliance with applicable laws, regulations, standards, and compliance schedules, including authority to require recordkeeping and to make inspections and conduct tests of designated facilities.

(4) Require owners or operators of designated facilities to install, maintain, and use emission monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such facilities; also authority for the State to make such data available to the public as reported and as correlated with applicable emission standards.

(b) The provisions of law or regulations which the State determines provide the authorities required by this section shall be specifically identified. Copies of such laws or regulations shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates that the laws or regulations are applicable to the designated pollutant(s) for which the plan is submitted.

(c) The plan shall show that the legal authorities specified in this section are available to the State at the time of submission of the plan. Legal authority adequate to meet the requirements of paragraphs (a)(3) and (4) of this section may be delegated to the State under section 114 of the Act.

(d) A State governmental agency other than the State air pollution control agency may be assigned responsibility for carrying out a portion of a plan if the plan demonstrates to the Administrator's satisfaction that the State governmental agency has the legal authority necessary to carry out that portion of the plan.

(e) The State may authorize a local agency to carry out a plan, or portion thereof, within the local agency's jurisdiction if the plan demonstrates to the Administrator's satisfaction that the local agency has the legal authority necessary to implement the plan or portion thereof, and that the authorization does not relieve the State of responsibility under the Act for carrying out the plan or portion thereof.

§ 60.27 Actions by the Administrator.

(a) The Administrator may, whenever he determines necessary, extend the period for submission of any plan or plan revision or portion thereof.

(b) After receipt of a plan or plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator will, within four months after the date required for submission of a plan or plan revision, approve or disapprove such plan or revision or each portion thereof.

(c) The Administrator will, after consideration of any State hearing record, promptly prepare and publish proposed regulations setting forth a plan, or portion thereof, for a State if:

(1) The State fails to submit a plan within the time prescribed;

(2) The State fails to submit a plan revision required by § 60.23(a)(2) within the time prescribed; or

(3) The Administrator disapproves the State plan or plan revision or any portion thereof, as unsatisfactory because the requirements of this subpart have not been met.

(d) The Administrator will, within six months after the date required for submission of a plan or plan revision, promulgate the regulations proposed under paragraph (c) of this section with such modifications as may be appropriate unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator determines to be approvable.

(e)(1) Except as provided in paragraph (e)(2) of this section, regulations proposed and promulgated by the Administrator under this section will prescribe emission standards of the same stringency as the corresponding emission guideline(s) specified in the final guideline document published under § 60.22(a) and will require final compliance with such standards as expeditiously as practicable but no later than the times specified in the guideline document.

(2) Upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply, the Administrator may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by this section in accordance with the criteria specified in § 60.24(f).

(f) If a State failed to hold a public hearing as required by § 60.23(c), the Administrator will provide opportunity for a hearing within the State prior to promulgation of a plan under paragraph (d) of this section.

§ 60.28 Plan revisions by the State.

(a) Plan revisions which have the effect of delaying compliance with applicable emission standards or increments of progress or of establishing less stringent emission standards shall be submitted to the Administrator within 60 days after adoption in accordance with the procedures and requirements applicable to development and submission of the original plan.

(b) More stringent emission standards, or orders which have the effect of accelerating compliance, may be submitted to the Administrator as plan revisions in accordance with the procedures and requirements applicable to development and submission of the original plan.

(c) A revision of a plan, or any portion thereof, shall not be considered part of an applicable plan until approved by the Administrator in accordance with this subpart.

§ 60.29 Plan revisions by the Administrator.

After notice and opportunity for public hearing in each affected State, the Administrator may revise any provision of an applicable plan if:

(a) The provision was promulgated by the Administrator, and

(b) The plan, as revised, will be consistent with the Act and with the requirements of this subpart.

Subpart C—Emission Guidelines and Compliance Times 73

§ 60.30 Scope.

This subpart contains emission guidelines and compliance times for the control of certain designated pollutants from certain designated facilities in accordance with section 111(d) of the Act and Subpart B.

§ 60.31 Definitions.

Terms used but not defined in this subpart have the meaning given them in the Act and in Subparts A and B of this part.

§ 60.32 Designated facilities.

(a) Sulfuric acid production units. The designated facility to which §§ 60.33 (a) and 60.34(a) apply is each existing "sulfuric acid production unit" as defined in § 60.81(a) of Subpart H.

§ 60.33 Emission guidelines.

(a) Sulfuric acid production units. The emission guideline for designated facilities is 0.25 gram sulfuric acid mist (as measured by Reference Method 8, of Appendix A) per kilogram of sulfuric acid produced (0.5 lb/ton), the production being expressed as 100 percent H_2SO_4.

§ 60.34 Compliance times.

(a) Sulfuric acid production units. Planning, awarding of contracts, and installation of equipment capable of attaining the level of the emission guideline established under § 60.33(a) can be accomplished within 17 months after the effective date of a State emission standard for sulfuric acid mist.

Subpart D—Standards of Performance for Fossil-Fuel Fired Steam Generators

§ 60.40 Applicability and designation of affected facility.[8,49,64]

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu per hour).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.[84]

(d) The requirements of §§ 60.44(a)(4), (a)(5), (b), and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.[84]

§ 60.41 Definitions.[8]

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in Subpart A of this part.

(a) "Fossil-fuel fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

(b) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(c) "Coal refuse" means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.[11]

(d) "Fossil fuel and wood residue-fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.[49]

(e) "Wood residue" means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.[49]

(f) "Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing Material. Designation D 388-66.[84]

§ 60.42 Standard for particulate matter.[8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.[49]

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.[18,76]

§ 60.43 Standard for sulfur dioxide.[2,8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.[49]

(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue.[49]

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2}=\frac{y(340)+z(520)}{y+z}$$

where:

PS_{SO_2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel.[49]

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

§ 60.44 Standard for nitrogen oxides.[8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel or gaseous fossil fuel and wood residue.[49]

(2) 130 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.[49]

(3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).[11,49]

(4) 260 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).[84]

(5) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.[84]

(b) Except as provided under paragraphs (c) and (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x}=\frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:

PS_{NO_x} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = is the percentage of total heat input derived from lignite;

x = is the percentage of total heat input derived from gaseous fossil fuel;

y = is the percentage of total heat input derived from liquid fossil fuel; and

z = is the percentage of total heat input derived from solid fossil fuel (except lignite).[11,49,84]

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for nitrogen oxides does not apply.[84]

(d) Cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.[84]

§ 60.45 Emission and fuel monitoring.[4,8,18,]

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.[57]

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:[57]

(1) For a fossil fuel-fired steam gen-

erator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.[57]

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under paragraph (d) of this section.[57]

(3) Notwithstanding § 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in § 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.[57]

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.[57]

(c) For performance evaluations under § 60.13(c) and calibration checks under § 60.13(d), the following procedures shall be used:[57]

(1) Reference Methods 6 or 7, as applicable, shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.[57]

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to this part.[57]

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	(1)	500
Liquid	1,000	500
Solid	1,500	500
Combinations	$1{,}000y+1{,}500z$	$500(x+y)+1{,}000z$

(1) Not applicable.

where:

x = the fraction of total heat input derived from gaseous fossil fuel, and

y = the fraction of total heat input derived from liquid fossil fuel, and

z = the fraction of total heat input derived from solid fossil fuel.[57]

(4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.[57]

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.[57]

(d) [Reserved][57]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):[49, 57]

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E=CF\left[\frac{20.9}{20.9-\text{percent } O_2}\right]$$

where:

E, C, F, and %O$_2$ are determined under paragraph (f) of this section.[57]

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E=CF_c\left[\frac{100}{\text{percent } CO_2}\right]$$

where:

E, C, F_c and %CO$_2$ are determined under paragraph (f) of this section.[57]

(f) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(1) E = pollutant emissions, ng/J (lb/million Btu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.[49]

(3) %O$_2$, %CO$_2$ = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (d) of this section.

(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to A.S.T.M. D 388-66, $F=2.723\times10^{-7}$ dscm/J (10,140 dscf/million Btu) and $F_c=0.532\times10^{-7}$ scm CO_2/J (1,980 scf CO_2/million Btu).[49]

(ii) For subbituminous and bituminous coal as classified according to A.S.T.M. D 388-66, $F=2.637\times10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c=0.486\times10^{-7}$ scm CO_2/J (1,810 scf CO_2/million Btu).[49]

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F=2.476\times10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c=0.384\times10^{-7}$ scm CO_2/J (1,430 scf CO_2/million Btu).[49, 67]

(iv) For gaseous fossil fuels, $F=2.347\times10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c=0.279\times10^{-7}$ scm CO_2/J (1,040 scf CO_2/million Btu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/million Btu) for butane.[49, 67]

(v) For bark $F=2.589\times10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c=0.500\times10^{-7}$ scm CO_2/J (1,860 scf CO_2/million Btu). For wood residue other than bark $F=2.492\times10^{-7}$ dscm/J (9,280 dscf/million Btu) and $F_c=0.494\times10^{-7}$ scm CO_2/J (1,840 scf CO_2/million Btu).[49, 67]

(vi) For lignite coal as classified according to A.S.T.M. D 388-66, $F=2.659\times10^{-7}$ dscm/J (9900 dscf/million Btu) and $F_c=0.516\times10^{-7}$ scm CO_2/J (1920 scf CO_2/million Btu).[64]

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2/J, or scf CO_2/million Btu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:[49]

$$F=10^{-6}\,\frac{[227.2\ (\text{pct. H})+95.5\ (\text{pct. C})+35.6\ (\text{pct. S})+8.7\ (\text{pct. N})-28.7\ (\text{pct. O})]}{GCV},$$

(SI units)

$$F=\frac{10^{6}[3.64(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)]}{GCV}$$

(English units)

$$F_c = \frac{2.0\times10^{-5}\ (\text{pct. C})}{\text{GCV}}.$$

(SI units)

$$F_c = \frac{321\times10^{3}(\%C)}{GCV}$$

(English units)

[23, 49, 67]

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using A.S.T.M. method D3178–74 or D3176 (solid fuels), or computed from results using A.S.T.M. methods D1137–53(70), D1945–64(73), or D1946–67(72) (gaseous fuels) as applicable.

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted, determined by the A.S.T.M. test methods D 2015–66(72) for solid fuels and D 1826–64(70) for gaseous fuels as applicable.[49]

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the *F* or F_c value shall be subject to the Administrator's approval.[49]

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the *F* or F_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F=\sum_{i=1}^{n} X_i F_i \text{ or } F_c=\sum_{i=1}^{n} X_i (F_c)_i$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or $(F_c)_i$ = the applicable *F* or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n = the number of fuels being burned in combination.[49]

(g) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Opacity*. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.[76]

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under § 60.43.

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44.

(Sec. 114. Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.46 Test methods and procedures.[8,18]

(a) The reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards as prescribed in §§ 60.42, 60.43, and 60.44 as follows:

(1) Method 1 for selection of sampling site and sample traverses.

(2) Method 3 for gas analysis to be used when applying Reference Methods 5, 6 and 7.

(3) Method 5 for concentration of particulate matter and the associated moisture content.

(4) Method 6 for concentration of SO_2, and

(5) Method 7 for concentration of NOx.

(b) For Method 5, Method 1 shall be used to select the sampling site and the number of traverse sampling points. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The probe and filter holder heating systems in the sampling train shall be set to provide a gas temperature no greater than 433 K (320°F).[49]

(c) For Methods 6 and 7, the sampling site shall be the same as that selected for Method 5. The sampling point in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). For Method 6, the sample shall be extracted at a rate proportional to the gas velocity at the sampling point.

(d) For Method 6, the minimum sampling time shall be 20 minutes and the minimum sampling volume 0.02 dscm (0.71 dscf) for each sample. The arithmetic mean of two samples shall constitute one run. Samples shall be taken at approximately 30-minute intervals.

(e) For Method 7, each run shall consist of at least four grab samples taken at approximately 15-minute intervals. The arithmetic mean of the samples shall constitute the run value.

(f) For each run using the methods specified by paragraphs (a)(3), (a)(4), and (a)(5) of this section, the emissions expressed in ng/J (lb/million Btu) shall be determined by the following procedure:

$$E = CF\,\frac{20.9}{20.9-\text{percent } O_2}$$

(1) E=pollutant emision ng/J (lb/million Btu).

(2) C=pollutant concentration, ng/dscm (lb/dscf), determined by method 5, 6, or 7.

(3) Percent O_2=oxygen content by volume (expressed as percent), dry basis. Percent oxygen shall be determined by using the integrated or grab sampling and anaylsis procedures of Method 3 as applicable.

The sample shall be obtained as follows:

(i) For determination of sulfur dioxide and nitrogen oxides emissions, the oxygen sample shall be obtained simultaneously at the same point in the duct as used to obtain the samples for Methods 6 and 7 determinations, respectively [§ 60.46(c)]. For Method 7, the oxygen sample shall be obtained using the grab sampling and analysis procedures of Method 3.

(ii) For determination of particulate emissions, the oxygen sample shall be obtained simultaneously by traversing the duct at the same sampling location used for each run of Method 5 under paragraph (b) of this section. Method 1 shall be used for selection of the number of traverse points except that no more than 12 sample points are required.

(4) F = a factor as determined in paragraphs (f) (4), (5) or (6) of § 60.45.

(g) When combinations of fossil fuels or fossil fuel and wood residue are fired, the heat input, expressed in watts (Btu/hr), is determined during each testing period by multiplying the gross calorific value of each fuel fired (in J/kg or Btu/lb) by the rate of each fuel burned (in kg/sec or lb/hr). Gross calorific values are determined in accordance with A.S.T.M. methods D 2015–66(72) (solid fuels), D 240–64(73) (liquid fuels), or D 1826–64(7) (gaseous fuels) as applicable. The method used to determine calorific value of wood residue must be approved by the Administrator. The owner or operator shall determine the rate of fuels burned during each testing period by suitable methods and shall confirm the rate by a material balance over the steam generation system.[49]

(Sec. 114. Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

37 FR 14877, 7/26/72 (2)
38 FR 28564, 10/15/73 (4)
39 FR 20790, 6/14/74 (8)
40 FR 2803, 1/16/75 (11)
40 FR 46250, 10/6/75 (18)
40 FR 59204, 12/22/75 (23)
41 FR 51397, 11/22/76 (49)
42 FR 5936, 1/31/77 (57)
42 FR 37936, 7/25/77 (64)
42 FR 41122, 8/15/77 (67)
42 FR 41424, 8/17/77 (68)
42 FR 61537, 12/5/77 (76)
43 FR 8800, 3/3/78 (83)
43 FR 9276, 3/7/78 (84)

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility.[8, 64]

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

§ 60.51 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Incinerator" means any furnace used in the process of burning solid waste for the purpose of reducing the volume of the waste by removing combustible matter.[8]

(b) "Solid waste" means refuse, more than 50 percent of which is municipal type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles, and noncombustible materials such as glass and rock.

(c) "Day" means 24 hours.[8]

§ 60.52 Standard for particulate matter.[8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent CO_2.

§ 60.53 Monitoring of operations.[8]

(a) The owner or operator of any incinerator subject to the provisions of this part shall record the daily charging rates and hours of operation.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.54 Test methods and procedures.[8]

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.52 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis and calculation of excess air, using the integrated sample technique.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30.0 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) If a wet scrubber is used, the gas analysis sample shall reflect flue gas conditions after the scrubber, allowing for carbon dioxide absorption by sampling the gas on the scrubber inlet and outlet sides according to either the procedure under paragraphs (c)(1) through (c)(5) of this section or the procedure under paragraphs (c)(1), (c)(2) and (c)(6) of this section as follows:

(1) The outlet sampling site shall be the same as for the particulate matter measurement. The inlet site shall be selected according to Method 1, or as specified by the Administrator.

(2) Randomly select 9 sampling points within the cross-section at both the inlet and outlet sampling sites. Use the first set of three for the first run, the second set for the second run, and the third set for the third run.

(3) Simultaneously with each particulate matter run, extract and analyze for CO_2 an integrated gas sample according to Method 3, traversing the three sample points and sampling at each point for equal increments of time. Conduct the runs at both inlet and outlet sampling sites.

(4) Measure the volumetric flow rate at the inlet during each particulate matter run according to Method 2, using the full number of traverse points. For the inlet make two full velocity traverses approximately one hour apart during each run and average the results. The outlet volumetric flow rate may be determined from the particulate matter run (Method 5).

(5) Calculate the adjusted CO_2 percentage using the following equation:

$$(\%\ CO_2)_{adj} = (\%\ CO_2)_{di}\ (Q_{di}/Q_{do})$$

where:

$(\%\ CO_2)_{adj}$ is the adjusted CO_2 percentage which removes the effect of CO_2 absorption and dilution air,

$(\%\ CO_2)_{di}$ is the percentage of CO_2 measured before the scrubber, dry basis,

Q_{di} is the volumetric flow rate before the scrubber, average of two runs, dscf/min (using Method 2), and

Q_{do} is the volumetric flow rate after the scrubber, dscf/min (using Methods 2 and 5).

(6) Alternatively, the following procedures may be substituted for the procedures under paragraphs (c)(3), (4), and (5) of this section:

(i) Simultaneously with each particulate matter run, extract and analyze for CO_2, O_2, and N_2 an integrated gas sample according to Method 3, traversing the three sample points and sampling for equal increments of time at each point. Conduct the runs at both the inlet and outlet sampling sites.

(ii) After completing the analysis of the gas sample, calculate the percentage of excess air (% EA) for both the inlet and outlet sampling sites using equation 3–1 in Appendix A to this part.

(iii) Calculate the adjusted CO_2 percentage using the following equation:

$$(\%\ CO_2)_{adj} = (\%\ CO_2)_{di} \left[\frac{100 + (\%\ EA)_i}{100 + (\%\ EA)_o} \right]$$

where:

$(\%\ CO_2)_{adj}$ is the adjusted outlet CO_2 percentage,

$(\%\ CO_2)_{di}$ is the percentage of CO_2 measured before the scrubber, dry basis,

$(\%\ EA)_i$ is the percentage of excess air at the inlet, and

$(\%\ EA)_o$ is the percentage of excess air at the outlet.

(d) Particulate matter emissions, expressed in g/dscm, shall be corrected to 12 percent CO_2 by using the following formula:

$$c_{12} = \frac{12c}{\%\ CO_2}$$

where:

c_{12} is the concentration of particulate matter corrected to 12 percent CO_2,

c is the concentration of particulate matter as measured by Method 5, and

$\%\ CO_2$ is the percentage of CO_2 as measured by Method 3, or when applicable, the adjusted outlet CO_2 percentage as determined by paragraph (c) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)
as amended
39 FR 20790, 6/14/74 (8)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

56

Subpart F—Standards of Performance for Portland Cement Plants

§ 60.60 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in portland cement plants: kiln, clinker cooler, raw mill system, finish mill system, raw mill dryer, raw material storage, clinker storage, finished product storage, conveyor transfer points, bagging and bulk loading and unloading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

§ 60.61 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Portland cement plant" means any facility manufacturing portland cement by either the wet or dry process.[8]

§ 60.62 Standard for particulate matter.[8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any kiln any gases which:

(1) Contain particulate matter in excess of 0.15 kg per metric ton of feed (dry basis) to the kiln (0.30 lb per ton).

(2) Exhibit greater than 20 percent opacity.[10]

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any clinker cooler any gases which:

(1) Contain particulate matter in excess of 0.050 kg per metric ton of feed (dry basis) to the kiln (0.10 lb per ton).

(2) Exhibit 10 percent opacity, or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility other than the kiln and clinker cooler any gases which exhibit 10 percent opacity, or greater.[18]

§ 60.63 Monitoring of operations.[8]

(a) The owner or operator of any portland cement plant subject to the provisions of this part shall record the daily production rates and kiln feed rates.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.64 Test methods and procedures.[8]

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.62 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 5, the minimum sampling time and minimum sample volume for each run, except when process variables or other factors justify otherwise to the satisfaction of the Administrator, shall be as follows:

(1) 60 minutes and 0.85 dscm (30.0 dscf) for the kiln.

(2) 60 minutes and 1.15 dscm (40.6 dscf) for the clinker cooler.

(c) Total kiln feed rate (except fuels), expressed in metric tons per hour on a dry basis, shall be determined during each testing period by suitable methods; and shall be confirmed by a material balance over the production system.

(d) For each run, particulate matter emissions, expressed in g/metric ton of kiln feed, shall be determined by dividing the emission rate in g/hr by the kiln feed rate. The emission rate shall be determined by the equation, $g/hr = Q_s \times c$, where Q_s=volumetric flow rate of the total effluent in dscm/hr as determined in accordance with paragraph (a)(3) of this section, and c=particulate concentration in g/dscm as determined in accordance with paragraph (a)(1) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

39 FR 20790, 6/14/74 (8)
39 FR 39872, 11/12/74 (10)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart G—Standards of Performance for Nitric Acid Plants

§ 60.70 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

§ 60.71 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Nitric acid production unit" means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

(b) "Weak nitric acid" means acid which is 30 to 70 percent in strength.

§ 60.72 Standard for nitrogen oxides.[3,8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain nitrogen oxides, expressed as NO_2, in excess of 1.5 kg per metric ton of acid produced (3.0 lb per ton), the production being expressed as 100 percent nitric acid.

(2) Exhibit 10 percent opacity, or greater.[18]

§ 60.73 Emission monitoring.[18]

(a) A continuous monitoring system for the measurement of nitrogen oxides shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be nitrogen dioxide (NO_2). The span shall be set at 500 ppm of nitrogen dioxide. Reference Method 7 shall be used for conducting monitoring system performance evaluations under § 60.13(c).

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/short ton). The conversion factor shall be established by measuring emissions with the continuous monitoring system concurrent with measuring emissions with the applicable reference method tests. Using only that portion of the continuous monitoring emission data that represents emission measurements concurrent with the reference method test periods, the conversion factor shall be determined by dividing the reference method test data averages by the monitoring data averages to obtain a ratio expressed in units of the applicable standard to units of the monitoring data, i.e., kg/metric ton per ppm (lb/short ton per ppm). The conversion factor shall be reestablished during any performance test under § 60.8 or any continuous monitoring system performance evaluation under § 60.13(c).

(c) The owner or operator shall record the daily production rate and hours of operation.

(d) [Reserved] [8]

(e) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as any three-hour period during which the average nitrogen oxides emissions (arithmetic average of three contiguous one-hour periods) as measured by a continuous monitoring system exceed the standard under § 60.72(a).[4,18]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.74 Test methods and procedures.[8]

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.72 as follows:

(1) Method 7 for the concentration of NO_x;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 7, the sample site shall be selected according to Method 1 and the sampling point shall be the centroid of the stack or duct or at a point no closer to the walls than 1 m (3.28 ft). Each run shall consist of at least four grab samples taken at approximately 15-minutes intervals. The arithmetic mean of the samples shall constitute the run value. A velocity traverse shall be performed once per run.

(c) Acid production rate, expressed in metric tons per hour of 100 percent nitric acid, shall be determined during each testing period by suitable methods and shall be confirmed by a material balance over the production system.

(d) For each run, nitrogen oxides, expressed in g/metric ton of 100 percent nitric acid, shall be determined by dividing the emission rate in g/hr by the acid production rate. The emission rate shall be determined by the equation,

$$g/hr = Q_s \times c$$

where Q_s = volumetric flow rate of the effluent in dscm/hr, as determined in accordance with paragraph (a)(3) of this section, and $c = NO_x$ concentration in g/dscm, as determined in accordance with paragraph (a)(1) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

38 FR 13562, 5/23/73 (3)
38 FR 28564, 10/15/73 (4)
39 FR 20790, 6/14/74 (8)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart H—Standards of Performance for Sulfuric Acid Plants

§ 60.80 Applicability and designation of affected facility. [64]

(a) The provisions of this subpart are applicable to each sulfuric acid production unit, which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

§ 60.81 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Sulfuric acid production unit" means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

(b) "Acid mist" means sulfuric acid mist, as measured by Method 8 of Appendix A to this part or an equivalent or alternative method. [8]

§ 60.82 Standard for sulfur dioxide. [8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4.

§ 60.83 Standard for acid mist. [3, 8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain acid mist, expressed as H_2SO_4, in excess of 0.075 kg per metric ton of acid produced (0.15 lb per ton), the production being expressed as 100 percent H_2SO_4.

(2) Exhibit 10 percent opacity, or greater. [18]

§ 60.84 Emission monitoring. [18]

(a) A continuous monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be sulfur dioxide (SO_2). Reference Method 8 shall be used for conducting monitoring system performance evaluations under § 60.13(c) except that only the sulfur dioxide portion of the Method 8 results shall be used. The span shall be set at 1000 ppm of sulfur dioxide.

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/short ton). The conversion factor shall be determined, as a minimum, three times daily by measuring the concentration of sulfur dioxide entering the converter using suitable methods (e.g., the Reich test, National Air Pollution Control Administration Publication No. 999-AP-13 and calculating the appropriate conversion factor for each eight-hour period as follows:

$$CF = k\left[\frac{1.000-0.015r}{r-s}\right]$$

where:

CF = conversion factor (kg/metric ton per ppm, lb/short ton per ppm).

k = constant derived from material balance. For determining CF in metric units, k = 0.0653. For determining CF in English units, k = 0.1306.

r = percentage of sulfur dioxide by volume entering the gas converter. Appropriate corrections must be made for air injection plants subject to the Administrator's approval.

s = percentage of sulfur dioxide by volume in the emissions to the atmosphere determined by the continuous monitoring system required under paragraph (a) of this section.

(c) The owner or operator shall record all conversion factors and values under paragraph (b) of this section from which they were computed (i.e., CF, r, and s).

(d) [Reserved] [8]

(e) For the purpose of reports under § 60.7(c), periods of excess emissions shall be all three-hour periods (or the arithmetic average of three consecutive one-hour periods) during which the integrated average sulfur dioxide emissions exceed the applicable standards under § 60.82. [4, 18]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.85 Test methods and procedures. [8]

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.82 and 60.83 as follows:

(1) Method 8 for the concentrations of SO_2 and acid mist;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) The moisture content can be considered to be zero. For Method 8 the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 1.15 dscm (40.6 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Acid production rate, expressed in metric tons per hour of 100 percent H_2SO_4, shall be determined during each testing period by suitable methods and shall be confirmed by a material balance over the production system.

(d) Acid mist and sulfur dioxide emissions, expressed in g/metric ton of 100 percent H_2SO_4, shall be determined by dividing the emission rate in g/hr by the acid production rate. The emission rate shall be determined by the equation, $g/hr = Q_s \times c$, where Q_s = volumetric flow rate of the effluent in dscm/hr as determined in accordance with paragraph (a)(3) of this section, and c = acid mist and SO_2 concentrations in g/dscm as determined in accordance with paragraph (a)(1) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

36 FR 24876, 12/23/71 (1)

as amended

38 FR 13562, 5/23/73 (3)
38 FR 28564, 10/15/73 (4)
39 FR 20790, 6/14/74 (8)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart I—Standards of Performance for Asphalt Concrete Plants [5]

§ 60.90 Applicability and designation of affected facility. [64]

(a) The affected facility to which the provisions of this subpart apply is each asphalt concrete plant. For the purpose of this subpart, an asphalt concrete plant is comprised only of any combination of the following: dryers; systems for screening, handling, storing, and weighing hot aggregate; systems for loading, transferring, and storing mineral filler; systems for mixing asphalt concrete; and the loading, transfer, and storage systems associated with emission control systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.91 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Asphalt concrete plant" means any facility, as described in § 60.90, used to manufacture asphalt concrete by heating and drying aggregate and mixing with asphalt cements.

§ 60.92 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 90 mg/dscm (0.04 gr/dscf).

(2) Exhibit 20 percent opacity, or greater. [18]

§ 60.93 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.92 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68,83]

36 FR 24876, 12/23/71 (1)
as amended
39 FR 9308, 3/8/74 (5)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

60

Subpart J—Standards of Performance for Petroleum Refineries[3]

§ 60.100 Applicability and designation of affected facility.[64,86]

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less associated with a small petroleum refinery. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator of fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this part.

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A.

(a) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) "Process gas" means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) "Fuel gas" means any gas which is generated by a petroleum refinery process unit and which is combusted, including any gaseous mixture of natural gas and fuel gas which is combusted.

(e) "Process upset gas" means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) "Refinery process unit" means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) "Fuel gas combustion device" means any equipment, such as process heaters, boilers and flares used to combust fuel gas, but does not include fluid coking unit and fluid catalytic cracking unit incinerator-waste heat boilers or facilities in which gases are combusted to produce sulfur or sulfuric acid.

(h) "Coke burn-off" means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

(i) "Claus sulfur recovery plant" means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.[86]

(j) "Oxidation control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.[86]

(k) "Reduction control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.[86]

(l) "Reduced sulfur compounds" mean hydrogen sulfide (H_2S), carbonyl sulfide (COS) and carbon disulfide (CS_2).[86]

(m) "Small petroleum refinery" means a petroleum refinery which has a crude oil processing capacity of 50,000 barrels per stream day or less, and which is owned or controlled by a refinery with a total combined crude oil processing capacity of 137,500 barrels per stream day or less.[86]

§ 60.102 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:[86]

(1) Particulate matter in excess of 1.0 kg/1000 kg (1.0 lb/1000 lb) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.[18,61,66]

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or sold fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43.0 g/MJ (0.10 lb/million Btu) of heat input attributable to such liquid or solid fossil fuel.[86]

§ 60.103 Standard for carbon monoxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from the fluid catalytic cracking unit catalyst regenerator any gases which contain carbon monoxide in excess of 0.050 percent by volume.

§ 60.104 Standard for sulfur dioxide.[86]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas which contains hydrogen sulfide in excess of 230 mg/dscm (0.10 gr/dscf), except that the gases resulting from the combustion of fuel gas may be treated to control sulfur dioxide emissions provided the owner or operator demonstrates to the satisfaction of the Administrator that this is as effective in preventing sulfur dioxide emissions to the atmosphere as restricting the H_2 concentration in the fuel gas to 230 mg/dscm or less. The combustion in a flare of process upset gas, or fuel gas which is released to the flare as a result of relief valve leakage, is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) 0.025 percent by volume of sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by an oxidation control system, or a reduction control system followed by incineration, or

(ii) 0.030 percent by volume of reduced sulfur compounds and 0.0010 percent by volume of hydrogen sulfide calculated as sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by a reduction control system not followed by incineration.

(b) [Reserved]

§ 60.105 Emission monitoring.[18]

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator as follows:

(1) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator. The continuous monitoring system shall be spanned at 60, 70, or 80 percent opacity.

(2) An instrument for continuously monitoring and recording the concentration of carbon monoxide in gases discharged into the atmosphere from fluid catalytic cracking unit catalyst regenerators. The span of this continuous monitoring system shall be 1,000 ppm.[86]

(3) A continuous monitoring system for the measurement of sulfur dioxide in the gases discharged into the atmosphere from the combustion of fuel gases (except where a continuous monitoring system for the measurement of hydrogen sulfide is installed under paragraph (a) (4) of this section). The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Speci-

fication 2 and for calibration checks under § 60.13(d), shall be sulfur dioxide (SO_2). The span shall be set at 100 ppm. For conducting monitoring system performance evaluations under § 60.13(c), Reference Method 6 shall be used.

(4) An instrument for continuously monitoring and recording concentrations of hydrogen sulfide in fuel gases burned in any fuel gas combustion device, if compliance with § 60.104(a)(1) is achieved by removing H_2S from the fuel gas before it is burned; fuel gas combustion devices having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas burned. The span of this continuous monitoring system shall be 300 ppm.[86]

(5) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases discharged into the atmosphere from any Claus sulfur recovery plant if compliance with § 60.104(a)(2) is achieved through the use of an oxidation control system or a reduction control system followed by incineration. The span of this continuous monitoring system shall be sent at 500 ppm.[86]

(6) An instrument(s) for continuously monitoring and recording the concentration of H_2S and reduced sulfur compounds in the gases discharged into the atmosphere from any Claus sulfur recovery plant if compliance with § 60.104(a)(2) is achieved through the use of a reduction control system not followed by incineration. The span(s) of this continuous monitoring system(s) shall be set at 20 ppm for monitoring and recording the concentration of H_2S and 600 ppm for monitoring and recording the concentration of reduced sulfur compounds.[86]

(b) [Reserved]

(c) The average coke burn-off rate (thousands of kilogram/hr) and hours of operation for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102 or § 60.103 shall be recorded daily.

(d) For any fluid catalytic cracking unit catalyst regenerator which is subject to § 60.102 and which utilizes an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil fuels (liters/hr or kilograms/hr) and the hours of operation during which liquid or solid fossil fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. All one-hour periods which contain two or more six-minute periods during which the average opacity as measured by the continuous monitoring system exceeds 30 percent.[61,63]

(2) Carbon monoxide. All hourly periods during which the average carbon monoxide concentration in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator subject to § 60.103 exceeds 0.050 percent by volume.[86]

(3) Sulfur dioxide. (i) Any three-hour period during which the average concentration of H_2S in any fuel gas combusted in any fuel gas combustion device subject to § 60.104(a)(1) exceeds 230 mg/dscm (0.10 gr/dscf), if compliance is achieved by removing H_2S from the fuel gas before it is burned; or any three-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from any fuel gas combustion device subject to § 60.104(a)(1) exceeds the level specified in § 60.104(a)(1), if compliance is achieved by removing SO_2 from the combusted fuel gases.[86]

(ii) Any twelve-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from any Claus sulfur recovery plant subject to § 60.104(a)(2) exceeds 250 ppm at zero percent oxygen on a dry basis if compliance with § 60.104(b) is achieved through the use of an oxidation control system or a reduction control system followed by incineration; or any twelve-hour period during which the average concentration of H_2S, or reduced sulfur compounds in the gases discharged into the atmosphere of any Claus sulfur plant subject to § 60.104(a)(2)(b) exceeds 10 ppm or 300 ppm, respectively, at zero percent oxygen and on a dry basis if compliance is achieved through the use of a reduction control system not followed by incineration.[86]

(4) Any six-hour period during which the average emissions (arithmetic average of six contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the standard under § 60.104.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[60,63]

§ 60.106 Test methods and procedures.

(a) For the purpose of determining compliance with § 60.102(a)(1), the following reference methods and calculation procedures shall be used:

(1) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 5 for the concentration of particulate matter and moisture content,

(ii) Method 1 for sample and velocity traverses, and

(iii) Method 2 for velocity and volumetric flow rate.

(2) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) For exhaust gases from the fluid catalytic cracking unit catalyst regenerator prior to the emission control system: the integrated sample techniques of Method 3 and Method 4 for gas analysis and moisture content, respectively; Method 1 for velocity traverses; and Method 2 for velocity and volumetric flow rate.

(4) Coke burn-off rate shall be determined by the following formula:

$$R_c=0.2982\ Q_{RE}\ (\%CO_2+\%CO)+2.088\ Q_{RA}-0.0994\ Q_{RE}\left(\frac{\%CO}{2}+\%CO_2+\%O_2\right)\ \text{(Metric Units)}$$

or

$$R_c=0.0186\ Q_{RE}\ (\%CO_2+\%CO)+0.1303\ Q_{RA}-0.0062\ Q_{RE}\left(\frac{\%CO}{2}+\%CO_2+\%O_2\right)\ \text{(English Units)}$$

where:

R_c = coke burn-off rate, kg/hr (English units: lb/hr).

0.2982 = metric units material balance factor divided by 100, kg-min/hr-m^3.

0.0186 = English units material balance factor divided by 100, lb-min/hr-ft^3.

Q_{RE} = fluid catalytic cracking unit catalyst regenerator exhaust gas flow rate before entering the emission control system, as determined by method 2, dscm/min (English units: dscf/min).

$\%CO_2$ = percent carbon dioxide by volume, dry basis, as determined by Method 3.

$\%CO$ = percent carbon monoxide by volume, dry basis, as determined by Method 3.

$\%O_2$ = percent oxygen by volume, dry basis, as determined by Method 3.

2.088 = metric units material balance factor divided by 100, kg-min/hr-m^3.

0.1303 = English units material balance factor divided by 100, lb-min/hr-ft^3.

Q_{RA} = air rate to fluid catalytic cracking unit catalyst regenerator, as determined from fluid catalytic cracking unit control room instrumentation, dscm/min (English units: dscf/min).

0.0994 = metric units material balance factor divided by 100, kg-min/hr-m^3.

0.0062 = English units material balance factor divided by 100, lb-min/hr-ft^3.

(5) Particulate emissions shall be determined by the following equation:

$$R_E=(60\times10^{-6})Q_{RV}C_s\ \text{(Metric Units)}$$

or

$$R_E=(8.57\times10^{-3})Q_{RV}C_s\ \text{(English Units)}$$

where:

R_E = particulate emission rate, kg/hr (English units: lb/hr).

60×10^{-6} = metric units conversion factor, min-kg/hr-mg.

8.57×10^{-3} = English units conversion factor, min-lb/hr-gr.

Q_{RV} = volumetric flow rate of gases discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator following the emission control system, as determined by Method 2, dscm/min (English units: dscf/min).

C_s = particulate emission concentration discharged into the atmosphere, as determined by Method 5, mg/dscm (English units: gr/dscf).

62

(6) For each run, emissions expressed in kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the catalyst regenerator shall be determined by the following equation:

$$R_e = 1000 \frac{R_s}{R_c} \text{ (Metric or English Units)}$$

where:

R_e = particulate emission rate, kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
1000 = conversion factor, kg to 1000 kg (English units: lb to 1000 lb).
R_s = particulate emission rate, kg/hr (English units: lb/hr).
R_c = coke burn-off rate, kg/hr (English units: lb/hr).

(7) In those instances in which auxiliary liquid or solid fossil fuels are burned in an incinerator-waste heat boiler, the rate of particulate matter emissions permitted under § 60.102(b) must be determined. Auxiliary fuel heat input, expressed in millions of cal/hr (English units: Millions of Btu/hr) shall be calculated for each run by fuel flow rate measurement and analysis of the liquid or solid auxiliary fossil fuels. For each run, the rate of particulate emissions permitted under § 60.102(b) shall be calculated from the following equation:

$$R_s = 1.0 + \frac{0.18\,H}{R_c} \text{ (Metric Units)}$$

or

$$R_s = 1.0 + \frac{0.10\,H}{R_c} \text{ (English Units)}$$

where:

R_s = allowable particulate emission rate, kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
1.0 = emission standard, 1.0 kg/1000 kg (English units: 1.0 lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
0.18 = metric units maximum allowable incremental rate of particulate emissions, g/million cal.
0.10 = English units maximum allowable incremental rate of particulate emissions, lb/million Btu.
H = heat input from solid or liquid fossil fuel, million cal/hr (English units: million Btu/hr).
R_c = coke burn-off rate, kg/hr (English units: lb/hr).

(b) For the purpose of determining compliance with § 60.103, the integrated sample technique of Method 10 shall be used. The sample shall be extracted at a rate proportional to the gas velocity at a sampling point near the centroid of the duct. The sampling time shall not be less than 60 minutes

(c) For the purpose of determining compliance with § 60.104(a)(1), Method 11 shall be used to determine the concentration of H_2S and Method 6 shall be used to determine the concentration of SO_2.[86]

(1) If Method 11 is used, the gases sampled shall be introduced into the sampling train at approximately atmospheric pressure. Where refinery fuel gas lines are operating at pressures substantially above atmosphere, this may be accomplished with a flow control valve. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples of equal sampling time shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For most fuel gases, sample times exceeding 20 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.[86]

(2) If Method 6 is used, Method 1 shall be used for velocity traverses and Method 2 for determining velocity and volumetric flow rate. The sampling site for determining SO_2 concentration by Method 6 shall be the same as for determining volumetric flow rate by Method 2. The sampling point in the duct for determining SO_2 concentration by Method 6 shall be at the centroid of the cross section if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than one meter from the wall. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples of equal sampling time shall constitute one run. Samples shall be taken at approximately 1-hour intervals.[86]

(d) For the purpose of determining compliance with § 60.104(a)(2), Method 6 shall be used to determine the concentration of SO_2 and Method 15 shall be used to determine the concentration of H_2S and reduced sulfur compounds.[86]

(1) If Method 6 is used, the procedure outlined in paragraph (c)(2) of this section shall be followed except that each run shall span a minimum of four consecutive hours of continuous sampling. A number of separate samples may be taken for each run, provided the total sampling time of these samples adds up to a minimum of four consecutive hours. Where more than one sample is used, the average SO_2 concentration for the run shall be calculated as the time weighted average of the SO_2 concentration for each sample according to the formula:

$$C_R = \sum_{i=1}^{N} C_{S_i} \frac{t_{S_i}}{T}$$

Where:

C_R = SO_2 concentration for the run.
N = Number of samples.
C_{S_i} = SO_2 concentration for sample i.
t_{S_i} = Continuous sampling time of sample i.
T = Total continuous sampling time of all N samples.[86]

(2) If Method 15 is used, each run shall consist of 16 samples taken over a minimum of three hours. The sampling point shall be at the centroid of the cross section of the duct if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than 1 meter from the wall. To insure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3 liters/minute (0.1 ft^3/min). The SO_2 equivalent for each run shall be calculated as the arithmetic average of the SO_2 equivalent of each sample during the run. Reference Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 15. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. Each run shall span a minimum of four consecutive hours of continuous sampling. A number of separate samples may be taken for each run provided the total sampling time of these samples adds up to a minimum of four consecutive hours. Where more than one sample is used, the average moisture content for the run shall be calculated as the time weighted average of the moisture content of each sample according to the formula:

$$B_{wo} = \sum_{i=1}^{N} B_{si} \left[\frac{t_{si}}{T}\right]$$

B_{wo} = Proportion by volume of water vapor in the gas stream for the run.
N = Number of samples.
B_{si} = Proportion by volume of water vapor in the gas stream for the sample i.
t_{si} = Continuous sampling time for sample i.
T = Total continuous sampling time of all N samples.

(Sec. 114 of the Clean Air Act, as amended [42 U.S.C. 7414]).[86]

36 FR 2487[illegible], 12/23/71 (1)

as amended

39 FR 9308, 3/8/74 (5)
40 FR 46250, 10/6/75 (18)
42 FR 32426, 6/24/77 (61)
42 FR 37936, 7/25/77 (64)
42 FR 39389, 8/4/77 (66)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)
43 FR 10866, 3/15/78 (86)

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids[5]

§ 60.110 Applicability and designation of affected facility.[64]

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.[8]

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151,412 liters (40,000 gallons), but not exceeding 245,000 liters (65,000 gallons, and commences construction or modification after March 8, 1974.

(2) Has a capacity greater than 245,000 liter (65,000 gallons), and commences construction or modification after June 11, 1973.

§ 60.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Storage vessel" means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Number 2 through Number 6 fuel oils as specified in A.S.T.M. D396–69, gas turbine fuel oils Numbers 2–GT through 4–GT as specified in A.S.T.M. D2880–71, or diesel fuel oils Numbers 2-D and 4–D as specified in A.S.T.M. D975–68.[8]

(c) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.[8]

(e) "Hydrocarbon" means any organic compound consisting predominantly of carbon and hydrogen.[8]

(f) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.[8]

(h) "Drilling and production facility" means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary non-transportation-related equipment used in the production of petroleum but does not include natural gasoline plants.[8]

(i) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(j) "Floating roof" means a storage vessel cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the petroleum liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(k) "Vapor recovery system" means a vapor gathering system capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(l) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM–D–323–58 (reapproved 1968).

§ 60.112 Standard for hydrocarbons.

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

§ 60.113 Monitoring of operations.

(a) The owner or operator of any storage vessel to which this subpart applies shall for each such storage vessel maintain a file of each type of petroleum liquid stored, of the typical Reid vapor pressure of each type of petroleum liquid stored, and of the dates of storage. Dates on which the storage vessel is empty shall be shown.

(b) The owner or operator of any storage vessel to which this subpart applies shall for each such storage vessel determine and record the average monthly storage temperature and true vapor pressure of the petroleum liquid stored at such temperature if:

(1) The petroleum liquid has a true vapor pressure, as stored, greater than 26 mm Hg (0.5 psia) but less than 78 mm Hg (1.5 psia) and is stored in a storage vessel other than one equipped with a floating roof, a vapor recovery system or their equivalents; or

(2) The petroleum liquid has a true vapor pressure, as stored, greater than 470 mm Hg (9.1 psia) and is stored in a storage vessel other than one equipped with a vapor recovery system or its equivalent.

(c) The average monthly storage temperature is an arithmetic average calculated for each calendar month, or portion thereof if storage is for less than a month, from bulk liquid storage temperatures determined at least once every 7 days.

(d) The true vapor pressure shall be determined by the procedures in API Bulletin 2517. This procedure is dependent upon determination of the storage temperature and the Reid vapor pressure, which requires sampling of the petroleum liquids in the storage vessels. Unless the Administrator requires in specific cases that the stored petroleum liquid be sampled, the true vapor pressure may be determined by using the average monthly storage temperature and the typical Reid vapor pressure. For those liquids for which certified specifications limiting the Reid vapor pressure exist, that Reid vapor pressure may be used. For other liquids, supporting analytical data must be made available on request to the Administrator when typical Reid vapor pressure is used.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

39 FR 9308, 3/8/74 (5)
39 FR 20790, 6/14/74 (8)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart L—Standards of Performance for Secondary Lead Smelters [5]

§ 60.120 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in secondary lead smelters: pot furnaces of more than 250 kg (550 lb) charging capacity, blast (cupola) furnaces, and reverberatory furnaces.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.121 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Reverberatory furnace" includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.

(b) "Secondary lead smelter" means any facility producing lead from a lead-bearing scrap material by smelting to the metallic form.

(c) "Lead" means elemental lead or alloys in which the predominant component is lead. [6]

§ 60.122 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a blast (cupola) or reverberatory furnace any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any pot furnace any gases which exhibit 10 percent opacity or greater. [18]

§ 60.123 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8 (b), shall be used to determine compliance with the standards prescribed in § 60.122 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. Particulate sampling shall be conducted during representative periods of furnace operation, including charging and tapping.

(Sec. 114. Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

36 FR 24876, 12/23/71 (1)

as amended

39 FR 9308, 3/8/74 (5)
39 FR 13776, 4/17/74 (6)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart M—Standards of Performance for Secondary Brass and Bronze Ingot Production Plants [5]

§ 60.130 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in secondary brass or bronze ingot production plants: reverberatory and electric furnaces of 1,000 kg (2,205 lb) or greater production capacity and blast (cupola) furnaces of 250 kg/hr (550 lb/hr) or greater production capacity.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.131 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Brass or bronze" means any metal alloy containing copper as its predominant constituent, and lesser amounts of zinc, tin, lead, or other metals.

(b) "Reverberatory furnace" includes the following types of reverberatory furnaces: Stationary, rotating, rocking, and tilting.

(c) "Electric furnace" means any furnace which uses electricity to produce over 50 percent of the heat required in the production of refined brass or bronze.

(d) "Blast furnace" means any furnace used to recover metal from slag.

§ 60.132 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a reverberatory furnace any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any blast (cupola) or electric furnace any gases which exhibit 10 percent opacity or greater. [18]

§ 60.133 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.132 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Method 1 for sample and velocity traverses.

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 120 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. Particulate matter sampling shall be conducted during representative periods of charging and refining, but not during pouring of the heat.

(Sec. 114. Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

36 FR 24876, 12/23/71 (1)

as amended

39 FR 9308, 3/8/74 (5)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart N—Standards of Performance for Iron and Steel Plants[5]

§ 60.140 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each basic oxygen process furnace.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.141 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Basic oxygen process furnace" (BOPF) means any furnace producing steel by charging scrap steel, hot metal, and flux materials into a vessel and introducing a high volume of an oxygen-rich gas.

(b) "Steel production cycle" means the operations required to produce each batch of steel and includes the following major functions: Scrap charging, preheating (when used), hot metal charging, primary oxygen blowing, additional oxygen blowing (when used), and tapping.

(c) "Startup means the setting into operation for the first steel production cycle of a relined BOPF or a BOPF which has been out of production for a minimum continuous time period of eight hours.[88]

§ 60.142 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exit from a control device and exhibit 10 percent opacity or greater, except that an opacity of greater than 10 percent but less than 20 percent may occur once per steel production cycle.[88]

§ 60.143 Monitoring of operations.[88]

(a) The owner or operator of an affected facility shall maintain a single time-measuring instrument which shall be used in recording daily the time and duration of each steel production cycle, and the time and duration of any diversion of exhaust gases from the main stack servicing the BOPF.

(b) The owner or operator of any affected facility that uses venturi scrubber emission control equipment shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±250 Pa (±1 inch water).

(2) A monitoring device for the continous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of the design water supply pressure. The monitoring device's pressure sensor or pressure tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations for the pressure sensor or tap.

(3) All monitoring devices shall be synchronized each day with the time-measuring instrument used under paragraph (a) of this section. The chart recorder error directly after synchronization shall not exceed 0.08 cm (1/32 inch).

(4) All monitoring devices shall use chart recorders which are operated at a minimum chart speed of 3.8 cm/hr (1.5 in/hr).

(5) All monitoring devices are to be recalibreated annually, and at other times as the Administrator may require, in accordance with the procedures under § 60.13(b)(3).

(c) Any owner or operator subject to requirements under paragraph (b) of this section shall report for each calendar quarter all measurements over any three-hour period that average more than 10 percent below the average levels maintained during the most recent performance test conducted under § 60.8 in which the affected facility demonstrated compliance with the standard under § 60.142(a)(1). The accuracy of the respective measurements, not to exceed the values specified in paragraphs (b)(1) and (b)(2) of this section, may be taken into consideration when determining the measurement results that must be reported.

§ 60.144 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.142 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for volumetric flow rate, and

(4) Method 3 for gas analysis.

(5) Method 9 for visible emissions. For the purpose of this subpart, opacity observations taken at 15-second intervals immediately before and after a diversion of exhaust gases from the stack may be considered to be consecutive for the purpose of computing an average opacity for a six-minute period. Observations taken during a diversion shall not be used in determining compliance with the opacity standard.[88]

(b) For Method 5, the sampling for each run shall continue for an integral number of cycles with total duration of at least 60 minutes. The sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times,

(c) Sampling of flue gases during each steel production cycle shall be discontinued whenever all flue gases are diverted from the stack and shall be resumed after each diversion period.[88]

(Sec. 114. Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

39 FR 9308, 3/8/74 (5)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)
43 FR 15600, 4/13/78 (88)

Subpart O—Standards of Performance for Sewage Treatment Plants [5]

§ 60.150 Applicability and designation of affected facility. [75]

(a) The affected facility is each incinerator that combusts wastes containing more than 10 percent sewage sludge (dry basis) produced by municipal sewage treatment plants, or each incinerator that charges more than 1000 kg (2205 lb) per day municipal sewage sludge (dry basis).

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.151 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

§ 60.152 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator of any sewage sludge incinerator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere of:

(1) Particulate matter at a rate in excess of 0.65 g/kg dry sludge input (1.30 lb/ton dry sludge input).

(2) Any gases which exhibit 20 percent opacity or greater. [18]

§ 60.153 Monitoring of operations. [75]

(a) The owner or operator of any sludge incinerator subject to the provisions of this subpart shall:

(1) Install, calibrate, maintain, and operate a flow measuring device which can be used to determine either the mass or volume of sludge charged to the incinerator. The flow measuring device shall have an accuracy of ±5 percent over its operating range.

(2) Provide access to the sludge charged so that a well mixed representative grab sample of the sludge can be obtained.

(3) Install, calibrate, maintain, and operate a weighing device for determining the mass of any municipal solid waste charged to the incinerator when sewage sludge and municipal solid waste are incinerated together. The weighing device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68,83]

§ 60.154 Test Methods and Procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.152 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Dry sludge charging rate shall be determined as follows:

(1) Determine the mass (S_M) or volume (S_V) of sludge charged to the incinerator during each run using a flow measuring device meeting the requirements of § 60.153(a)(1). If total input during a run is measured by a flow measuring device, such readings shall be used. Otherwise, record the flow measuring device readings at 5-minute intervals during a run. Determine the quantity charged during each interval by averaging the flow rates at the beginning and end of the interval and then multiplying the average for each interval by the time for each interval. Then add the quantity for each interval to determine the total quantity charged during the entire run, (S_M) or (S_V).

(2) Collect samples of the sludge charged to the incinerator in non-porous collecting jars at the beginning of each run and at approximately 1-hour intervals thereafter until the test ends, and determine for each sample the dry sludge content (total solids residue) in accordance with "224 G. Method for Solid and Semisolid Samples," *Standard Methods for the Examination of Water and Wastewater*, Thirteenth Edition, American Public Health Association, Inc., New York, N.Y., 1971, pp. 539–41, except that:

(i) Evaporating dishes shall be ignited to at least 103°C rather than the 550°C specified in step 3(a)(1).

(ii) Determination of volatile residue, step 3(b) may be deleted.

(iii) The quantity of dry sludge per unit sludge charged shall be determined in terms of either R_{DV} (metric units: mg dry sludge/liter sludge charged or English units: lb/ft³) or R_{DM} (metric units: mg dry sludge/mg sludge charged or English units: lb/lb).

(3) Determine the quantity of dry sludge per unit sludge charged in terms of either R_{DV} or R_{DM}.

(i) If the volume of sludge charged is used:

$$S_D=(60\times10^{-6})\frac{R_{DV}S_V}{T} \text{ (Metric Units)}$$

or

$$S_D=(8.021)\frac{R_{DV}S_V}{T} \text{ (English Units)}$$

where:

S_D=average dry sludge charging rate during the run, kg/hr (English units: lb/hr).
R_{DV}=average quantity of dry sludge per unit volume of sludge charged to the incinerator, mg/l (English units: lb/ft³).
S_V=sludge charged to the incinerator during the run, m³ (English units: gal).
T=duration of run, min (English units: min).
60×10^{-6}=metric units conversion factor, l-kg-min/m³-mg-hr.
8.021=English units conversion factor, ft³-min/gal-hr. 6

(ii) If the mass of sludge charged is used:

$$S_D=(60)\frac{R_{DM}S_M}{T} \text{ (Metric or English Units)}$$

where:

S_D=average dry sludge charging rate during the run, kg/hr (English units: lb/hr).
R_{DM}=average ratio of quantity of dry sludge to quantity of sludge charged to the incinerator, mg/mg (English units: lb/lb).
S_M=sludge charged during the run, kg (English units: lb).
T=duration of run, min (Metric or English units). 6
60=conversion factor, min/hr (Metric or English units).

(d) Particulate emission rate shall be determined by:

$$C_{aw}=C_sQ_s \text{ (Metric or English Units)}$$

where:

C_{aw}=particulate matter mass emissions, mg/hr (English units: lb/hr). 7
C_s=particulate matter concentration, mg/m³ (English units: lb/dscf).
Q_s=volumetric stack gas flow rate, dscm/hr (English units: dscf/hr). Q_s and C_s shall be determined using Methods 2 and 5, respectively.

(e) Compliance with § 60.152(a) shall be determined as follows:

$$C_{ds}=(10^{-3})\frac{C_{aw}}{S_D} \text{ (Metric Units)}$$

or

$$C_{ds}=(2000)\frac{C_{aw}}{S_D} \text{ (English Units)}$$

where:

C_{ds}=particulate emission discharge, g/kg dry sludge (English units: lb/ton dry sludge).
10^{-3}=Metric conversion factor, g/mg.
2000=English conversion factor, lb/ton.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68,83]

36 FR 24876, 12/23/71 (1)

as amended

39 FR 9308, 3/8/74 (5)
39 FR 13776, 4/17/74 (6)
39 FR 15396, 5/3/74 (7)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
42 FR 58520, 11/10/77 (75)
43 FR 8800, 3/3/78 (83)

Subpart P—Standards of Performance for Primary Copper Smelters [26]

§ 60.160 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are aplicable to the following affected facilities in primary copper smelters: dryer, roaster, smelting furnace, and copper converter.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

§ 60.161 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary copper smelter" means any installation or any intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Dryer" means any facility in which a copper sulfide ore concentrate charge is heated in the presence of air to eliminate a portion of the moisture from the charge, provided less than 5 percent of the sulfur contained in the charge is eliminated in the facility.

(c) "Roaster" means any facility in which a copper sulfide ore concentrate charge is heated in the presence of air to eliminate a significant portion (5 percent or more) of the sulfur contained in the charge.

(d) "Calcine" means the solid materials produced by a roaster.

(e) "Smelting" means processing techniques for the melting of a copper sulfide ore concentrate or calcine charge leading to the formation of separate layers of molten slag, molten copper, and/or copper matte.

(f) "Smelting furnace" means any vessel in which the smelting of copper sulfide ore concentrates or calcines is performed and in which the heat necessary for smelting is provided by an electric current, rapid oxidation of a portion of the sulfur contained in the concentrate as it passes through an oxidizing atmosphere, or the combustion of a fossil fuel.

(g) "Copper converter" means any vessel to which copper matte is charged and oxidized to copper.

(h) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

(i) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(j) "Reverberatory smelting furnace" means any vessel in which the smelting of copper sulfide ore concentrates or calcines is performed and in which the heat necessary for smelting is provided primarily by combustion of a fossil fuel.

(k) "Total smelter charge" means the weight (dry basis) of all copper sulfides ore concentrates processed at a primary copper smelter, plus the weight of all other solid materials introduced into the roasters and smelting furnaces at a primary copper smelter, except calcine, over a one-month period.

(l) "High level of volatile impurities" means a total smelter charge containing more than 0.2 weight percent arsenic, 0.1 weight percent antimony, 4.5 weight percent lead or 5.5 weight percent zinc, on a dry basis.

§ 60.162 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dryer any gases which contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

§ 60.163 Standard for sulfur dioxide.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any roaster, smelting furnace, or copper converter any gases which contain sulfur dioxide in excess of 0.065 percent by volume, except as provided in paragraphs (b) and (c) of this section.

(b) Reverberatory smelting furnaces shall be exempted from paragraph (a) of this section during periods when the total smelter charge at the primary copper smelter contains a high level of volatile impurities.

(c) A change in the fuel combusted in a reverberatory furnace shall not be considered a modification under this part.

§ 60.164 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dryer any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid to comply with the standard set forth in § 60.163, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.165 Monitoring of operations.

(a) The owner or operator of any primary copper smelter subject to § 60.163 (b) shall keep a monthly record of the total smelter charge and the weight percent (dry basis) of arsenic, antimony, lead and zinc contained in this charge. The analytical methods and procedures employed to determine the weight of the total smelter charge and the weight percent of arsenic, antimony, lead and zinc shall be approved by the Administrator and shall be accurate to within plus or minus ten percent. [30]

(b) The owner or operator of any primary copper smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any dryer. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any roaster, smelting furnace or copper converter subject to § 60.163 (a). The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c) the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gas used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13 (d), shall be sulfur dioxide.

(c) Six-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the four consecutive 6-hour periods of each operating day. Each six-hour average shall be determined as the arithmetic mean of the appropriate six contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (b) of this section.

(d) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring

system installed under paragraph (b) of this section, exceeds the standard under § 60.164(a).

(2) Sulfur dioxide. All six-hour periods during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under § 60.163, exceed the level of the standard. The Administrator will not consider emissions in excess of the level of the standard for less than or equal to 1.5 percent of the six-hour periods during the quarter as indicative of a potential violation of § 60.11(d) provided the affected facility, including air pollution control equipment, is maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions during these periods. Emissions in excess of the level of the standard during periods of startup, shutdown, and malfunction are not to be included within the 1.5 percent.[74]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.166 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.162, 60.163 and 60.164 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.165(b). One 6-hour average period shall constitute one run. The monitoring system drift during any run shall not exceed 2 percent of span.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

41 FR 2332, 1/15/76 (26)
41 FR 8346, 2/26/76 (30)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
42 FR 57126, 11/1/77 (74)
43 FR 8800, 3/3/78 (83)

Subpart Q—Standards of Performance for Primary Zinc Smelters [26]

§ 60.170 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in primary zinc smelters: roaster and sintering machine.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

§ 60.171 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary zinc smelter" means any installation engaged in the production, or any intermediate process in the production, of zinc or zinc oxide from zinc sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Roaster" means any facility in which a zinc sulfide ore concentrate charge is heated in the presence of air to eliminate a significant portion (more than 10 percent) of the sulfur contained in the charge.

(c) "Sintering machine" means any furnace in which calcines are heated in the presence of air to agglomerate the calcines into a hard porous mass called "sinter."

(d) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

§ 60.172 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine any gases which contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

§ 60.173 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any roaster any gases which contain sulfur dioxide in excess of 0.065 percent by volume.

(b) Any sintering machine which eliminates more than 10 percent of the sulfur initially contained in the zinc sulfide ore concentrates will be considered as a roaster under paragraph (a) of this section.

§ 60.174 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid plant to comply with the standard set forth in § 60.173, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.175 Monitoring of operations.

(a) The owner or operator of any primary zinc smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any sintering machine. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any roaster subject to § 60.173. The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c), the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gas used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13 (d), shall be sulfur dioxide.

(b) Two-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the twelve consecutive 2-hour periods of each operating day. Each two-hour average shall be determined as the arithmetic mean of the appropriate two contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (a) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.174(a).

(2) Sulfur dioxide. Any two-hour period, as described in paragraph (b) of this section, during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.173.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.176 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.172, 60.173 and 60.174 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.175(a). One 2-hour average period shall constitute one run.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)
  as amended
    41 FR 2332, 1/15/76 (26)
    42 FR 37936, 7/25/77 (64)
    42 FR 41424, 8/17/77 (68)
    43 FR 8800, 3/3/78 (83)

Subpart R—Standards of Performance for Primary Lead Smelters [26]

§ 60.180 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in primary lead smelters: sintering machine, sintering machine discharge end, blast furnace, dross reverberatory furnace, electric smelting furnace, and converter.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

§ 60.181 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary lead smelter" means any installation or any intermediate process engaged in the production of lead from lead sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Sintering machine" means any furnace in which a lead sulfide ore concentrate charge is heated in the presence of air to eliminate sulfur contained in the charge and to agglomerate the charge into a hard porous mass called "sinter."

(c) "Sinter bed" means the lead sulfide ore concentrate charge within a sintering machine.

(d) "Sintering machine discharge end" means any apparatus which receives sinter as it is discharged from the conveying grate of a sintering machine.

(e) "Blast furnace" means any reduction furnace to which sinter is charged and which forms separate layers of molten slag and lead bullion.

(f) "Dross reverberatory furnace" means any furnace used for the removal or refining of impurities from lead bullion.

(g) "Electric smelting furnace" means any furnace in which the heat necessary for smelting of the lead sulfide ore concentrate charge is generated by passing an electric current through a portion of the molten mass in the furnace.

(h) "Converter" means any vessel to which lead concentrate or bullion is charged and refined.

(i) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

§ 60.182 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end any gases which contain particulate matter in excess of 59 mg/dscm (0.022 gr/dscf).

§ 60.183 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine, electric smelting furnace, or converter gases which contain sulfur dioxide in excess of 0.065 percent by volume.

§ 60.184 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid plant to comply with the standard set forth in § 60.183, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.185 Monitoring of operations.

(a) The owner or operator of any primary lead smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any sintering machine, electric furnace or converter subject to § 60.183. The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c), the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gases used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13(d), shall be sulfur dioxide.

(b) Two-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the twelve consecutive two-hour periods of each operating day. Each two-hour average shall be determined as the arithmetic mean of the appropriate two contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (a) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.184(a).

(2) Sulfur dioxide. Any two-hour period, as described in paragraph (b) of this section, during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.183.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.186 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.182, 60.183 and 60.184 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.185(a). One 2-hour average period shall constitute one run.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

41 FR 2332, 1/15/76 (26)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart S—Standards of Performance for Primary Aluminum Reduction Plants[27]

§ 60.190 Applicability and designation of affected facility.[64]

(a) The affected facilities in primary aluminum reduction plants to which this subpart applies are potroom groups and anode bake plants.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 23, 1974, is subject to the requirements of this subpart.

§ 60.191 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary aluminum reduction plant" means any facility manufacturing aluminum by electrolytic reduction.

(b) "Anode bake plant" means a facility which produces carbon anodes for use in a primary aluminum reduction plant.

(c) "Potroom" means a building unit which houses a group of electrolytic cells in which aluminum is produced.

(d) "Potroom group" means an uncontrolled potroom, a potroom which is controlled individually, or a group of potrooms ducted to the same control system.

(e) "Roof monitor" means that portion of the roof of a potroom where gases not captured at the cell exit from the potroom.

(f) "Aluminum equivalent" means an amount of aluminum which can be produced from a ton of anodes produced by an anode bake plant as determined by § 60.195(e).

(g) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.195 or by equivalent or alternative methods [see § 60.8(b)].

(h) "Primary control system" means an air pollution control system designed to remove gaseous and particulate fluorides from exhaust gases which are captured at the cell.

(i) "Secondary control system" means an air pollution control system designed to remove gaseous and particulate fluorides from gases which escape capture by the primary control system.

§ 60.192 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of:

(1) 1 kg/metric ton (2 lb/ton) of aluminum produced for vertical stud Soderberg and horizontal stud Soderberg plants;

(2) 0.95 kg/metric ton (1.9 lb/ton) of aluminum produced for potroom groups at prebake plants; and

(3) 0.05 kg/metric ton (0.1 lb/ton) of aluminum equivalent for anode bake plants.

§ 60.193 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any potroom group any gases which exhibit 10 percent opacity or greater, or

(2) From any anode bake plant any gases which exhibit 20 percent opacity or greater.

§ 60.194 Monitoring of operations.

(a) The owner or operator of any affected facility subject to the provisions of this subpart shall install, calibrate, maintain, and operate monitoring devices which can be used to determine daily the weight of aluminum and anode produced. The weighing devices shall have an accuracy of ±5 percent over their operating range.

(b) The owner or operator of any affected facility shall maintain a record of daily production rates of aluminum and anodes, raw material feed rates, and cell or potline voltages.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.195 Test methods and procedures.

(a) Except as provided in § 60.8(b), reference methods specified in Appendix A of this part shall be used to determine compliance with the standards prescribed in § 60.192 as follows:

(1) For sampling emissions from stacks:

(i) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(2) For sampling emissions from roof monitors not employing stacks or pollutant collection systems:

(i) Method 14 for the concentration of total fluorides and associated moisture content,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 and Method 14 for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) For sampling emissions from roof monitors not employing stacks but equipped with pollutant collection systems, the procedures under § 60.8(b) shall be followed.

(b) For Method 13A or 13B, the sampling time for each run shall be at least eight hours for any potroom sample and at least four hours for any anode bake plant sample, and the minimum sample volume shall be 6.8 dscm (240 dscf) for any potroom sample and 3.4 dscm (120 dscf) for any anode bake plant sample except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for each affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined using applicable methods specified under paragraph (a) of this section.

(d) The rate of aluminum production shall be determined as follows:

(1) Determine the weight of aluminum in metric tons produced during a period from the last tap before a run starts until the first tap after the run ends using a monitoring device which meets the requirements of § 60.194(a).

(2) Divide the weight of aluminum produced by the length of the period in hours.

(e) For anode bake plants, the aluminum equivalent for anodes produced shall be determined as follows:

(1) Determine the average weight (metric tons) of anode produced in the anode bake plant during a representative oven cycle using a monitoring device which meets the requirements of § 60.194(a).

(2) Determine the average rate of anode production by dividing the total weight of anodes produced during the representative oven cycle by the length of the cycle in hours.

(3) Calculate the aluminum equivalent for anodes produced by multiplying the average rate of anode production by two. (Note: an owner or operator may establish a different multiplication factor by submitting production records of the tons of aluminum produced and the concurrent tons of anode consumed by potrooms.)

(f) For each run, potroom group emissions expressed in kg/metric ton of aluminum produced shall be determined using the following equation:

$$E_{pg}=\frac{(C_sQ_s)_1\,10^{-6}+(C_sQ_s)_2\,10^{-6}}{M}$$

where:

E_{pg}=potroom group emissions of total fluorides in kg/metric ton of aluminum produced.

C_s=concentration of total fluorides in mg/dscm as determined by Method 13A or 13B, or by Method 14, as applicable.

Q_s=volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2 and/or Method 14, as applicable

10^{-6}=conversion factor from mg to kg.

M=rate of aluminum production in metric ton/hr as determined by § 60.195(d).

$(C_sQ_s)_1$=product of C_s and Q_s for measurements of primary control system effluent gas streams.

$(C_sQ_s)_2$=product of C_s and Q_s for measurements of secondary control system or roof monitor effluent gas streams.

(g) For each run, as applicable, anode bake plant emissions expressed in kg/metric ton of aluminum equivalent shall

74

be determined using the following equation:

$$E_{bp}=\frac{C_s Q_s 10^{-6}}{M_e}$$

Where:

E_{bp} = anode bake plant emissions of total fluorides in kg/metric ton of aluminum equivalent.

C_s = concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-6} = conversion factor from mg to kg.

M_e = aluminum equivalent for anodes produced by anode bake plants in metric ton/hr as determined by § 60.195(e).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)
as amended
41 FR 3825, 1/26/76 (27)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart T—Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants[14]

§ 60.200 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each wet-process phosphoric acid plant. For the purpose of this subpart, the affected facility includes any combination of: reactors, filters, evaporators, and hot-wells.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.201 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Wet-process phosphoric acid plant" means any facility manufacturing phosphoric acid by reacting phosphate rock and acid.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.204, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.202 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 10.0 g/metric ton of equivalent P_2O_5 feed (0.020 lb/ton).

§ 60.203 Monitoring of operations.

(a) The owner or operator of any wet-process phosphoric acid plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any wet-process phosphoric acid plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus bearing feed using a monitoring device for measuring mass flowrate which meets the requirements of paragraph (a) of this section and then by proceeding according to § 60.204(d)(2).

(c) The owner or operator of any wet-process phosphoric acid subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

§ 60.204 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8 (b), shall be used to determine compliance with the standard prescribed in § 60.202 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.203(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E=\frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.204(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

36 FR 24876, 12/23/71 (1)

as amended

40 FR 33152, 8/6/75 (14)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart U—Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants [14]

§ 60.210 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each superphosphoric acid plant. For the purpose of this subpart, the affected facility includes any combination of: evaporators, hotwells, acid sumps, and cooling tanks.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.211 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Superphosphoric acid plant" means any facility which concentrates wet-process phosphoric acid to 66 percent or greater P_2O_5 content by weight for eventual consumption as a fertilizer.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.214, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.212 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 5.0 g/metric ton of equivalent P_2O_5 feed (0.010 lb/ton).

§ 60.213 Monitoring of operations.

(a) The owner or operator of any superphosphoric acid plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ± 5 percent over its operating range.

(b) The owner or operator of any superphosphoric acid plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.214(d)(2).

(c) The owner or operator of any superphosphoric acid plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ± 5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.214 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.212 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content.

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.213(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed, shall be determined using the following equation:

$$E=\frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.214(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

40 FR 33152, 8/6/75 (14)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart V—Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants[14]

§ 60.220 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each granular diammonium phosphate plant. For the purpose of this subpart, the affected facility includes any combination of: reactors, granulators, dryers, coolers, screens, and mills.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.221 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Granular diammonium phosphate plant" means any plant manufacturing granular diammonium phosphate by reacting phosphoric acid with ammonia.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.224, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.222 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 30 g/metric ton of equivalent P_2O_5 feed (0.060 lb/ton).

§ 60.223 Monitoring of operations.

(a) The owner or operator of any granular diammonium phosphate plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any granular diammonium phosphate plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.224(d)(2).

(c) The owner or operator of any granular diammonium phosphate plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[64, 83]

§ 60.224 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.222 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.223(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E=\frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5.
C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.
Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.
10^{-3} = Conversion factor for mg to g.
$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.224(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[64, 83]

36 FR 24876, 12/23/71 (1)
as amended
40 FR 33152, 8/6/75 (14)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart W—Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants [14]

§ 60.230 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each triple superphosphate plant. For the purpose of this subpart, the affected facility includes any combination of: mixers, curing belts (dens), reactors, granulators, dryers, cookers, screens, mills, and facilities which store run-of-pile triple superphosphate.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.231 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Triple superphosphate plant" means any facility manufacturing triple superphosphate by reacting phosphate rock with phosphoric acid. A rule-of-pile triple superphosphate plant includes curing and storing.

(b) "Run-of-pile triple superphosphate" means any triple superphosphate that has not been processed in a granulator and is composed of particles at least 25 percent by weight of which (when not caked) will pass through a 16 mesh screen.

(c) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.234, or equivalent or alternative methods.

(d) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorus pentoxide, fed to the process.

§ 60.232 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 100 g/metric ton of equivalent P_2O_5 feed (0.20 lb/ton).

§ 60.233 Monitoring of operations.

(a) The owner or operator of any triple superphosphate plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any triple superphosphate plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.234(d)(2).

(c) The owner or operator of any triple superphosphate plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.234 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.232 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.233(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E=\frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.234(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)
as amended
40 FR 33152, 8/6/75 (14)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart X—Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities [14]

§ 60.240 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each granular triple superphosphate storage facility. For the purpose of this subpart, the affected facility includes any combination of: storage or curing piles, conveyors, elevators, screens, and mills.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.241 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Granular triple superphosphate storage facility" means any facility curing or storing granular triple superphosphate.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.244, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 stored" means the quantity of phosphorus, expressed as phosphorus pentoxide, being cured or stored in the affected facility.

(d) "Fresh granular triple superphosphate" means granular triple superphosphate produced no more than 10 days prior to the date of the performance test.

§ 60.242 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 0.25 g/hr/metric ton of equivalent P_2O_5 stored (5.0×10^{-4} lb/hr/ton of equivalent P_2O_5 stored).

§ 60.243 Monitoring of operations.

(a) The owner or operator of any granular triple superphosphate storage facility subject to the provisions of this subpart shall maintain an accurate account of triple superphosphate in storage to permit the determination of the amount of equivalent P_2O_5 stored.

(b) The owner or operator of any granular triple superphosphate storage facility shall maintain a daily record of total equivalent P_2O_5 stored by multiplying the percentage P_2O_5 content, as determined by § 60.244(f)(2), times the total mass of granular triple superphosphate stored.

(c) The owner or operator of any granular triple superphosphate storage facility subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing sytem. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.244 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.242 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Except as provided under paragraph (e) of this section, all performance tests on granular triple superphosphate storage facilities shall be conducted only when the following quantities of product are being cured or stored in the facility:

(1) Total granular triple superphosphate—at least 10 percent of the building capacity.

(2) Fresh granular triple superphosphate—at least 20 percent of the amount of triple superphosphate in the building.

(e) If the provisions set forth in paragraph (d)(2) of this section exceed production capabilities for fresh granular triple superphosphate, the owner or operator shall have at least five days maximum production of fresh granular triple superphosphate in the building during a performance test.

(f) Equivalent P_2O_5 stored shall be determined as follows:

(1) Determine the total mass stored during each run using an accountability system meeting the requirements of § 60.243(a).

(2) Calculate the equivalent P_2O_5 stored by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass stored. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11-12. Other methods may be approved by the Administrator.

(g) For each run, emissions expressed in g/hr/metric ton of equivalent P_2O_5 stored shall be determined using the following equation:

$$E=\frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/hr/metric ton of equivalent P_2O_5 stored.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric tons as measured by § 60.244(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)

as amended

40 FR 33152, 8/6/75 (14)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart Y—Standards of Performance for Coal Preparation Plants [26]

§ 60.250 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 200 tons per day: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 24, 1974, is subject to the requirements of this subpart.[71]

§ 60.251 Definitions.

As used in this subpart, all terms not defined herein have the meaning given them in the Act and in subpart A of this part.

(a) "Coal preparation plant" means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) "Bituminous coal" means solid fossil fuel classified as bituminous coal by A.S.T.M. Designation D-388-66.

(c) "Coal" means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by A.S.T.M. Designation D-388-66.

(d) "Cyclonic flow" means a spiraling movement of exhaust gases within a duct or stack.

(e) "Thermal dryer" means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) "Pneumatic coal-cleaning equipment" means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) "Coal processing and conveying equipment" means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) "Coal storage system" means any facility used to store coal except for open storage piles.

(i) "Transfer and loading system" means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any pneumatic coal cleaning equipment, gases which:

(1) Contain particulate matter in excess of 0.040 g/dscm (0.018 gr/dscf).

(2) Exhibit 10 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

§ 60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±3° Fahrenheit.

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gage.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b)(3) of this part.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

§ 60.254 Test methods and procedures.

(a) The reference methods in Appendix A of this part, except as provided in § 60.8(b), are used to determine compliance with the standards prescribed in § 60.252 as follows:

(1) Method 5 for the concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run is at least 60 minutes and the minimum sample volume is 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator. Sampling is not to be started until 30 minutes after start-up and is to be terminated before shutdown procedures commence. The owner or operator of the affected facility shall eliminate cyclonic flow during performance tests in a manner acceptable to the Administrator.

(c) The owner or operator shall construct the facility so that particulate emissions from thermal dryers or pneumatic coal cleaning equipment can be accurately determined by applicable test methods and procedures under paragraph (a) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

36 FR 24876, 12/23/71 (1)

as amended

41 FR 2231, 1/15/76 (26)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
42 FR 44812, 9/7/77 (71)
43 FR 8800, 3/3/78 (83)

Subpart Z—Standards of Performance for Ferroalloy Production Facilities[33,35]

§ 60.260 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities: electric submerged arc furnaces which produce silicon metal, ferrosilicon, calcium silicon, silicomanganese zirconium, ferrochrome silicon, silvery iron, high-carbon ferrochrome, charge chrome, standard ferromanganese, silicomanganese, ferromanganese silicon, or calcium carbide; and dust-handling equipment.[35]

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 21, 1974, is subject to the requirements of this subpart.

§ 60.261 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Electric submerged arc furnace" means any furnace wherein electrical energy is converted to heat energy by transmission of current between electrodes partially submerged in the furnace charge.

(b) "Furnace charge" means any material introduced into the electric submerged arc furnace and may consist of, but is not limited to, ores, slag, carbonaceous material, and limestone.

(c) "Product change" means any change in the composition of the furnace charge that would cause the electric submerged arc furnace to become subject to a different mass standard applicable under this subpart.

(d) "Slag" means the more or less completely fused and vitrified matter separated during the reduction of a metal from its ore.

(e) "Tapping" means the removal of slag or product from the electric submerged arc furnace under normal operating conditions such as removal of metal under normal pressure and movement by gravity down the spout into the ladle.

(f) "Tapping period" means the time duration from initiation of the process of opening the tap hole until plugging of the tap hole is complete.

(g) "Furnace cycle" means the time period from completion of a furnace product tap to the completion of the next consecutive product tap.

(h) "Tapping station" means that general area where molten product or slag is removed from the electric submerged arc furnace.

(i) "Blowing tap" means any tap in which an evolution of gas forces or projects jets of flame or metal sparks beyond the ladle, runner, or collection hood.[35]

(j) "Furnace power input" means the resistive electrical power consumption of an electric submerged arc furnace as measured in kilowatts.

(k) "Dust-handling equipment" means any equipment used to handle particulate matter collected by the air pollution control device (and located at or near such device) serving any electric submerged arc furnace subject to this subpart.

(l) "Control device" means the air pollution control equipment used to remove particulate matter generated by an electric submerged arc furnace from an effluent gas stream.

(m) "Capture system" means the equipment (including hoods, ducts, fans, dampers, etc.) used to capture or transport particulate matter generated by an affected electric submerged arc furnace to the control device.

(n) "Standard ferromanganese" means that alloy as defined by A.S.T.M. designation A99–66.

(o) "Silicomanganese" means that alloy as defined by A.S.T.M. designation A483–66.

(p) "Calcium carbide" means material containing 70 to 85 percent calcium carbide by weight.

(q) "High-carbon ferrochrome" means that alloy as defined by A.S.T.M. designation A101–66 grades HC1 through HC6.

(r) "Charge chrome" means that alloy containing 52 to 70 percent by weight chromium, 5 to 8 percent by weight carbon, and 3 to 6 percent by weight silicon.

(s) "Silvery iron" means any ferrosilicon, as defined by A.S.T.M. designation 100–69, which contains less than 30 percent silicon.

(t) "Ferrochrome silicon" means that alloy as defined by A.S.T.M. designation A482–66.

(u) "Silicomanganese zirconium" means that alloy containing 60 to 65 percent by weight silicon, 1.5 to 2.5 percent by weight calcium, 5 to 7 percent by weight zirconium, 0.75 to 1.25 percent by weight aluminum, 5 to 7 percent by weight manganese, and 2 to 3 percent by weight barium.

(v) "Calcium silicon" means that alloy as defined by A.S.T.M. designation A495–64.

(w) "Ferrosilicon" means that alloy as defined by A.S.T.M. designation A100–69 grades A, B, C, D, and E which contains 50 or more percent by weight silicon.

(x) "Silicon metal" means any silicon alloy containing more than 96 percent silicon by weight.

(y) "Ferromanganese silicon" means that alloy containing 63 to 66 percent by weight manganese, 28 to 32 percent by weight silicon, and a maximum of 0.08 percent by weight carbon.

§ 60.262 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any electric submerged arc furnace any gases which:

(1) Exit from a control device and contain particulate matter in excess of 0.45 kg/MW-hr (0.99 lb/MW-hr) while silicon metal, ferrosilicon, calcium silicon, or silicomanganese zirconium is being produced.

(2) Exit from a control device and contain particulate matter in excess of 0.23 kg/MW-hr (0.51 lb/MW-hr) while high-carbon ferrochrome, charge chrome, standard ferromanganese, silicomanganese, calcium carbide, ferrochrome silicon, ferromanganese silicon, or silvery iron is being produced.

(3) Exit from a control device and exhibit 15 percent opacity or greater.

(4) Exit from an electric submerged arc furnace and escape the capture system and are visible without the aid of instruments. The requirements under this subparagraph apply only during periods when flow rates are being established under § 60.265(d).

(5) Escape the capture system at the tapping station and are visible without the aid of instruments for more than 40 percent of each tapping period. There are no limitations on visible emissions under this subparagraph when a blowing tap occurs. The requirements under this subparagraph apply only during periods when flow rates are being established under § 60.265(d).

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dust-handling equipment any gases which exhibit 10 percent opacity or greater.

§ 60.263 Standard for carbon monoxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any electric submerged arc furnace any gases which contain, on a dry basis, 20 or greater volume percent of carbon monoxide. Combustion of such gases under conditions acceptable to the Administrator constitutes compliance with this section. Acceptable conditions include, but are not limited to, flaring of gases or use of gases as fuel for other processes.

§ 60.264 Emission monitoring.

(a) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain and operate a continuous monitoring system for measurement of the opacity of emissions discharged into the atmosphere from the control device(s).

(b) For the purpose of reports required under § 60.7(c), the owner or operator shall report as excess emissions all six-minute periods in which the average opacity is 15 percent or greater.

(c) The owner or operator subject to the provisions of this subpart shall submit a written report of any product change to the Administrator. Reports of product changes must be postmarked not later than 30 days after implementation of the product change.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.265 Monitoring of operations.

(a) The owner or operator of any electric submerged arc furnace subject to the provisions of this subpart shall maintain daily records of the following information:

(1) Product being produced.

(2) Description of constituents of furnace charge, including the quantity, by weight.

(3) Time and duration of each tapping period and the identification of material tapped (slag or product.)

(4) All furnace power input data obtained under paragraph (b) of this section.

(5) All flow rate data obtained under paragraph (c) of this section or all fan motor power consumption and pressure drop data obtained under paragraph (e) of this section.

(b) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device to measure and continuously record the furnace power input. The furnace power input may be measured at the output or input side of the transformer. The device must have an accuracy of ±5 percent over its operating range.

(c) The owner or operator subject to the provisions of this subpart shall install, calibrate, and maintain a monitoring device that continuously measures and records the volumetric flow rate through each separately ducted hood of the capture system, except as provided under paragraph (e) of this section. The owner or operator of an electric submerged arc furnace that is equipped with a water cooled cover which is designed to contain and prevent escape of the generated gas and particulate matter shall monitor only the volumetric flow rate through the capture system for control of emissions from the tapping station. The owner or operator may install the monitoring device(s) in any appropriate location in the exhaust duct such that reproducible flow rate monitoring will result. The flow rate monitoring device must have an accuracy of ±10 percent over its normal operating range and must be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device relative to Methods 1 and 2 of Appendix A to this part.

(d) When performance tests are conducted under the provisions of § 60.8 of this part to demonstrate compliance with the standards under §§ 60.262(a) (4) and (5), the volumetric flow rate through each separately ducted hood of the capture system must be determined using the monitoring device required under paragraph (c) of this section. The volumetric flow rates must be determined for furnace power input levels at 50 and 100 percent of the nominal rated capacity of the electric submerged arc furnace. At all times the electric submerged arc furnace is operated, the owner or operator shall maintain the volumetric flow rate at or above the appropriate levels for that furnace power input level determined during the most recent performance test. If emissions due to tapping are captured and ducted separately from emissions of the electric submerged arc furnace, during each tapping period the owner or operator shall maintain the exhaust flow rates through the capture system over the tapping station at or above the levels established during the most recent performance test. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. The owner or operator may request that these flow rates be reestablished by conducting new performance tests under § 60.8 of this part.

(e) The owner or operator may as an alternative to paragraph (c) of this section determine the volumetric flow rate through each fan of the capture system from the fan power consumption, pressure drop across the fan and the fan performance curve. Only data specific to the operation of the affected electric submerged arc furnace are acceptable for demonstration of compliance with the requirements of this paragraph. The owner or operator shall maintain on file a permanent record of the fan performance curve (prepared for a specific temperature) and shall:

(1) Install, calibrate, maintain, and operate a device to continuously measure and record the power consumption of the fan motor (measured in kilowatts), and

(2) Install, calibrate, maintain, and operate a device to continuously measure and record the pressure drop across the fan. The fan power consumption and pressure drop measurements must be synchronized to allow real time comparisons of the data. The monitoring devices must have an accuracy of ±5 percent over their normal operating ranges.

(f) The volumetric flow rate through each fan of the capture system must be determined from the fan power consumption, fan pressure drop, and fan performance curve specified under paragraph (e) of this section, during any performance test required under § 60.8 of this part to demonstrate compliance with the standards under §§ 60.262(a) (4) and (5). The owner or operator shall determine the volumetric flow rate at a representative temperature for furnace power input levels of 50 and 100 percent of the nominal rated capacity of the electric submerged arc furnace. At all times the electric submerged arc furnace is operated, the owner or operator shall maintain the fan power consumption and fan pressure drop at levels such that the volumetric flow rate is at or above the levels established during the most recent performance test for that furnace power input level. If emissions due to tapping are captured and ducted separately from emissions of the electric submerged arc furnace, during each tapping period the owner or operator shall maintain the fan power consumption and fan pressure drop at levels such that the volumetric flow rate is at or above the levels established during the most recent performance test. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. The owner or operator may request that these flow rates be reestablished by conducting new performance tests under § 60.8 of this part. The Administrator may require the owner or operator to verify the fan performance curve by monitoring necessary fan operating parameters and determining the gas volume moved relative to Methods 1 and 2 of Appendix A to this part.

(g) All monitoring devices required under paragraphs (c) and (e) of this section are to be checked for calibration annually in accordance with the procedures under § 60.13(b).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.266 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8 (b), shall be used to determine compliance with the standards prescribed in § 60.262 and § 60.263 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content except that the heating systems specified in paragraphs 2.1.2 and 2.1.4 of Method 5 are not to be used when the carbon monoxide content of the gas stream exceeds 10 percent by volume, dry basis.

(2) Method 1 for sample and velocity traverses.

(3) Method 2 for velocity and volumetric flow rate.

(4) Method 3 for gas analysis, including carbon monoxide.

(b) For Method 5, the sampling time for each run is to include an integral number of furnace cycles. The sampling time for each run must be at least 60 minutes and the minimum sample volume must be 1.8 dscm (64 dscf) when sampling emissions from open electric submerged arc furnaces with wet scrubber control devices, sealed electric submerged arc furnaces, or semi-enclosed electric submerged arc furnaces. When sampling emissions from other types of installations, the sampling time for each run must be at least 200 minutes and the minimum sample volume must be 5.7 dscm (200 dscf). Shorter sampling times or smaller sampling volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) During the performance test, the owner or operator shall record the maximum open hood area (in hoods with segmented or otherwise moveable sides) under which the process is expected to be operated and remain in compliance with all standards. Any future operation of the hooding system with open areas in excess of the maximum is not permitted.

(d) The owner or operator shall construct the control device so that volumetric flow rates and particulate matter emissions can be accurately determined by applicable test methods and procedures.

(e) During any performance test required under § 60.8 of this part, the owner or operator shall not allow gaseous diluents to be added to the effluent gas stream after the fabric in an open pressurised fabric filter collector unless the total gas volume flow from the collector is accurately determined and considered in the determination of emissions.

(f) When compliance with § 60.263 is to be attained by combusting the gas stream in a flare, the location of the sampling site for particulate matter is to be upstream of the flare.

(g) For each run, particulate matter emissions, expressed in kg/hr (lb/hr), must be determined for each exhaust stream at which emissions are quantified using the following equation:

$$E_s = C_s Q_s$$

where:

E_s = Emissions of particulate matter in kg/hr (lb/hr).

C_s = Concentration of particulate matter in kg/dscm (lb/dscf) as determined by Method 5.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr (dscf/hr) as determined by Method 2.

(h) For Method 5, particulate matter emissions from the affected facility, expressed in kg/MW-hr (lb/MW-hr) must be determined for each run using the following equation:

$$E = \frac{\sum_{s=1}^{N} E_s}{P}$$ 35

where:

E = Emissions of particulate from the affected facility, in kg/MW-hr (lb/MW-hr).

N = Total number of exhaust streams at which emissions are quantified.

E_s = Emission of particulate matter from each exhaust stream in kg/hr (lb/hr), as determined in paragraph (g) of this section.

p = Average furnace power input during the sampling period, in megawatts as determined according to § 60.263 (b).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).$^{68, 83}$

36 FR 24876, 12/23/71 (1)
as amended
41 FR 18498, 5/4/76 (33)
41 FR 20659, 5/20/76 (35)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces [16]

§ 60.270 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in steel plants: electric arc furnaces and dust-handling equipment.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 21, 1974, is subject to the requirements of this subpart.[71]

§ 60.271 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Electric arc furnace" (EAF) means any furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes. Furnaces from which the molten steel is cast into the shape of finished products, such as in a foundry, are not affected facilities included within the scope of this definition. Furnaces which, as the primary source of iron, continuously feed prereduced ore pellets are not affected facilities within the scope of this definition.

(b) "Dust-handling equipment" means any equipment used to handle particulate matter collected by the control device and located at or near the control device for an EAF subject to this subpart.

(c) "Control device" means the air pollution control equipment used to remove particulate matter generated by an EAF(s) from the effluent gas stream.

(d) "Capture system" means the equipment (including ducts, hoods, fans, dampers, etc.) used to capture or transport particulate matter generated by an EAF to the air pollution control device.

(e) "Charge" means the addition of iron and steel scrap or other materials into the top of an electric arc furnace.

(f) "Charging period" means the time period commencing at the moment an EAF starts to open and ending either three minutes after the EAF roof is returned to its closed position or six minutes after commencement of opening of the roof, whichever is longer.

(g) "Tap" means the pouring of molten steel from an EAF.

(h) "Tapping period" means the time period commencing at the moment an EAF begins to tilt to pour and ending either three minutes after an EAF returns to an upright position or six minutes after commencing to tilt, whichever is longer.

(i) "Meltdown and refining" means that phase of the steel production cycle when charge material is melted and undesirable elements are removed from the metal.

(j) "Meltdown and refining period" means the time period commencing at the termination of the initial charging period and ending at the initiation of the tapping period, excluding any intermediate charging periods.

(k) "Shop opacity" means the arithmetic average of 24 or more opacity observations of emissions from the shop taken in accordance with Method 9 of Appendix A of this part for the applicable time periods.

(l) "Heat time" means the period commencing when scrap is charged to an empty EAF and terminating when the EAF tap is completed.

(m) "Shop" means the building which houses one or more EAF's.

(n) "Direct shell evacuation system" means any system that maintains a negative pressure within the EAF above the slag or metal and ducts these emissions to the control device.

§ 60.272 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from an electric arc furnace any gases which:

(1) Exit from a control device and contain particulate matter in excess of 12 mg/dscm (0.0052 gr/dscf).

(2) Exit from a control device and exhibit three percent opacity or greater.

(3) Exit from a shop and, due solely to operations of any EAF(s), exhibit greater than zero percent shop opacity except:

(i) Shop opacity greater than zero percent, but less than 20 percent, may occur during charging periods.

(ii) Shop opacity greater than zero percent, but less than 40 percent, may occur during tapping periods.

(iii) Opacity standards under paragraph (a)(3) of this section shall apply only during periods when flow rates and pressures are being established under § 60.274 (c) and (f).

(iv) Where the capture system is operated such that the roof of the shop is closed during the charge and the tap, and emissions to the atmosphere are prevented until the roof is opened after completion of the charge or tap, the shop opacity standards under paragraph (a)(3) of this section shall apply when the roof is opened and shall continue to apply for the length of time defined by the charging and/or tapping periods.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from dust-handling equipment any gases which exhibit 10 percent opacity or greater.

§ 60.273 Emission monitoring.

(a) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart.

(b) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be reported are defined as all six-minute periods during which the average opacity is three percent or greater.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

§ 60.274 Monitoring of operations.

(a) The owner or operator subject to the provisions of this subpart shall maintain records daily of the following information:

(1) Time and duration of each charge;

(2) Time and duration of each tap;

(3) All flow rate data obtained under paragraph (b) of this section, or equivalent obtained under paragraph (d) of this section; and

(4) All pressure data obtained under paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, the owner or operator subject to the provisions of this subpart shall install, calibrate, and maintain a monitoring device that continously records the volumetric flow rate through each separately ducted hood. The monitoring device(s) may be installed in any appropriate location in the exhaust duct such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an accuracy of ±10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device(s) relative to Methods 1 and 2 of Appendix A of this part.

(c) When the owner or operator of an EAF is required to demonstrate compliance with the standard under § 60.272 (a)(3) and at any other time the Administrator may require (under section 114 of the Act, as amended), the volumetric flow rate through each separately ducted hood shall be determined during all periods in which the hood is operated for the purpose of capturing emissions from the EAF using the monitoring device under paragraph (b) of this section. The owner or operator may petition the Administrator for reestablishment of these flow rates whenever the owner or operator can demonstrate to the Administrator's satisfaction that the EAF operating conditions upon which the flow rates were previously established are no longer applicable. The flow rates determined during the most recent demonstration of compliance shall be maintained (or may be exceeded) at the appropriate level for each applicable period. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility.

(d) The owner or operator may petition the Administrator to approve any alternative method that will provide a continuous record of operation of each emission capture system.

(e) Where emissions during any phase of the heat time are controlled by use of a direct shell evacuation system, the owner or operator shall install, calibrate, and maintain a monitoring device that continuously records the pressure in the free space inside the EAF. The pressure shall be recorded as 15-minute integrated averages. The monitoring device may be installed in any appropriate location in the EAF such that reproducible results will be obtained. The pressure monitoring device shall have an accuracy of ±5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions.

(f) When the owner or operator of an EAF is required to demonstrate compliance with the standard under § 60.272 (a)(3) and at any other time the Administrator may require (under section 114 of the Act, as amended), the pressure in the free space inside the furnace shall be determined during the meltdown and refining period(s) using the monitoring device under paragraph (e) of this section. The owner or operator may petition the Administrator for reestablishment of the 15-minute integrated average pressure whenever the owner or operator can demonstrate to the Administrator's satisfaction that the EAF operating conditions upon which the pressures were previously established are no longer applicable. The pressure determined during the most recent demonstration of compliance shall be maintained at all times the EAF is operating in a meltdown and refining period. Operation at higher pressures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility.

(g) Where the capture system is designed and operated such that all emissions are captured and ducted to a control device, the owner or operator shall not be subject to the requirements of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.275 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with the standards prescribed under § 60.272 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least four hours. When a single EAF is sampled, the sampling time for each run shall also include an integral number of heats. Shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. The minimum sample volume shall be 4.5 dscm (160 dscf).

(c) For the purpose of this subpart, the owner or operator shall conduct the demonstration of compliance with 60.272(a)(3) and furnish the Administrator a written report of the results of the test.

(d) During any performance test required under § 60.8 of this part, no gaseous diluents may be added to the effluent gas stream after the fabric in any pressurized fabric filter collector, unless the amount of dilution is separately determined and considered in the determination of emissions.

(e) When more than one control device serves the EAF(s) being tested, the concentration of particulate matter shall be determined using the following equation:

$$C_s = \frac{\sum_{n=1}^{N} (C_s Q_s)_n}{\sum_{n=1}^{N} (Q_s)_n}$$

where:

C_s=concentration of particulate matter in mg/dscm (gr/dscf) as determined by method 5.

N=total number of control devices tested.

Q_s=volumetric flow rate of the effluent gas stream in dscm/hr (dscf/hr) as determined by method 2.

$(C_s Q_s)_n$ or $(Q_s)_n$=value of the applicable parameter for each control device tested.

(f) Any control device subject to the provisions of this subpart shall be designed and constructed to allow measurement of emissions using applicable test methods and procedures.

(g) Where emissions from any EAF(s) are combined with emissions from facilities not subject to the provisions of this subpart but controlled by a common capture system and control device, the owner or operator may use any of the following procedures during a performance test:

(1) Base compliance on control of the combined emissions.

(2) Utilize a method acceptable to the Administrator which compensates for the emissions from the facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (g)(1) and (g)(2) of this section.

(h) Where emissions from any EAF(s) are combined with emissions from facilities not subject to the provisions of this subpart, the owner or operator may use any of the following procedures for demonstrating compliance with § 60.272 (a)(3):

(1) Base compliance on control of the combined emissions.

(2) Shut down operation of facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (h)(1) and (h)(2) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

36 FR 24876, 12/23/71 (1)
as amended
40 FR 43850, 9/23/75 (16)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
42 FR 44812, 9/7/77 (71)
43 FR 8800, 3/3/78 (83)

86

Subpart BB—Standards of Performance for Kraft Pulp Mills [82]

60.280 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in kraft pulp mills: digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, recovery furnace, smelt dissolving tank, lime kiln, and condensate stripper system. In pulp mills where kraft pulping is combined with neutral sulfite semichemical pulping, the provisions of this subpart are applicable when any portion of the material charged to an affected facility is produced by the kraft pulping operation.

(b) Any facility under paragraph (a) of this section that commences construction or modification after September 24, 1976, is subject to the requirements of this subpart.

§ 60.281 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in Subpart A.

(a) "Kraft pulp mill" means any stationary source which produces pulp from wood by cooking (digesting) wood chips in a water solution of sodium hydroxide and sodium sulfide (white liquor) at high temperature and pressure. Regeneration of the cooking chemicals through a recovery process is also considered part of the kraft pulp mill.

(b) "Neutral sulfite semichemical pulping operation" means any operation in which pulp is produced from wood by cooking (digesting) wood chips in a solution of sodium sulfite and sodium bicarbonate, followed by mechanical defibrating (grinding).

(c) "Total reduced sulfur (TRS)" means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide, that are released during the kraft pulping operation and measured by Reference Method 16.

(d) "Digester system" means each continuous digester or each batch digester used for the cooking of wood in white liquor, and associated flash tank(s), below tank(s), chip steamer(s), and condenser(s).

(e) "Brown stock washer system" means brown stock washers and associated knotters, vacuum pumps, and filtrate tanks used to wash the pulp following the digester system.

(f) "Multiple-effect evaporator system" means the multiple-effect evaporators and associated condenser(s) and hotwell(s) used to concentrate the spent cooking liquid that is separated from the pulp (black liquor).

(g) "Black liquor oxidation system" means the vessels used to oxidize, with air or oxygen, the black liquor, and associated storage tank(s).

(h) "Recovery furnace" means either a straight kraft recovery furnace or a cross recovery furnace, and includes the direct-contact evaporator for a direct-contact furnace.

(i) "Straight kraft recovery furnace" means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains 7 weight percent or less of the total pulp solids from the neutral sulfite semichemical process or has green liquor sulfidity of 28 percent or less.

(j) "Cross recovery furnace" means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains more than 7 weight percent of the total pulp solids from the neutral sulfite semichemical process and has a green liquor sulfidity of more than 28 percent.

(k) "Black liquor solids" means the dry weight of the solids which enter the recovery furnace in the black liquor.

(l) "Green liquor sulfidity" means the sulfidity of the liquor which leaves the smelt dissolving tank.

(m) "Smelt dissolving tank" means a vessel used for dissolving the smelt collected from the recovery furnace.

(n) "Lime kiln" means a unit used to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

(o) "Condensate stripper system" means a column, and associated condensers, used to strip, with air or steam, TRS compounds from condensate streams from various processes within a kraft pulp mill.

§ 60.282 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any recovery furnace any gases which:

(i) Contain particulate matter in excess of 0.10 g/dscm (0.044 gr/dscf) corrected to 8 percent oxygen.

(ii) Exhibit 35 percent opacity or greater.

(2) From any smelt dissolving tank any gases which contain particulate matter in excess of 0.1 g/kg black liquor solids (dry weight)[0.2 lb/ton black liquor solids (dry weight)].

(3) From any lime kiln any gases which contain particulate matter in excess of:

(i) 0.15 g/dscm (0.067 gr/dscf) corrected to 10 percent oxygen, when gaseous fossil fuel is burned.

(ii) 0.30 g/dscm (0.13 gr/dscf) corrected to 10 percent oxygen, when liquid fossil fuel is burned.

§ 60.283 Standard for total reduced sulfur (TRS).

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the following conditions are met:

(i) The gases are combusted in a lime kiln subject to the provisions of paragraph (a)(5) of this section; or

(ii) The gases are combusted in a recovery furnace subject to the provisions of paragraphs (a)(2) or (a)(3) of this section; or

(iii) The gases are combusted with other waste gases in an incinerator or other device, or combusted in a lime kiln or recovery furnace not subject to the provisions of this subpart, and are subjected to a minimum temperature of 1200° F. for at least 0.5 second; or

(iv) It has been demonstrated to the Administrator's satisfaction by the owner or operator that incinerating the exhaust gases from a new, modified, or reconstructed black liquor oxidation system or brown stock washer system in an existing facility is technologically or economically not feasible. Any exempt system will become subject to the provisions of this subpart if the facility is changed so that the gases can be incinerated.

(v) The gases from the digester system, brown stock washer system, condensate stripper system, or black liquor oxidation system are controlled by a means other than combustion. In this case, these systems shall not discharge any gases to the atmosphere which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to the actual oxygen content of the untreated gas stream.[91]

(2) From any straight kraft recovery furnace any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(3) From any cross recovery furnace any gases which contain TRS in excess of 25 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(4) From any smelt dissolving tank any gases which contain TRS in excess of 0.0084 g/kg black liquor solids (dry weight) [0.0168 lb/ton liquor solids (dry weight)].

(5) From any lime kiln any gases which contain TRS in excess of 8 ppm by volume on a dry basis, corrected to 10 percent oxygen.

§ 60.284 Monitoring of emissions and operations.

(a) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring systems:

(1) A continuous monitoring system to monitor and record the opacity of the gases discharged into the atmosphere from any recovery furnace. The span of this system shall be set at 70 percent opacity.

(2) Continuous monitoring systems to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from any lime kiln, recovery furnace, digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system, except where the provisions of § 60.283(a)(1) (iii) or (iv) apply. These systems shall be located downstream of the control device(s) and the span(s) of these continuous monitoring system(s) shall be set:

(i) At a TRS concentration of 30 ppm for the TRS continuous monitoring system, except that for any cross recovery furnace the span shall be set at 50 ppm.

(ii) At 20 percent oxygen for the continuous oxygen monitoring system.

(b) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device which measures the combustion temperature at the point of incineration of effluent gases which are emitted from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system where the provisions of § 60.283(a)(1)(iii) apply. The monitoring device is to be certified by the manufacturer to be accurate within ±1 percent of the temperature being measured.

(2) For any lime kiln or smelt dissolving tank using a scrubber emission control device:

(i) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the control equipment. The monitoring device is to be certified by the manufacturer to be accurate to within a gage pressure of ±500 pascals (ca. ±2 inches water gage pressure).

(ii) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±15 percent of design scrubbing liquid supply pressure. The pressure sensor or tap is to be located close to the scrubber liquid discharge point. The Administrator may be consulted for approval of alternative locations.

(c) Any owner or operator subject to the provisions of this subpart shall, except where the provisions of § 60.283(a)(1)(iv) or § 60.283(a)(4) apply.

(1) Calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(2) Calculate and record on a daily basis 12-hour average oxygen concentrations for the two consecutive periods of each operating day for the recovery furnace and lime kiln. These 12-hour averages shall correspond to the 12-hour average TRS concentrations under paragraph (c)(1) of this section and shall be determined as an arithmetic mean of the appropriate 12 contiguous 1-hour average oxygen concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(3) Correct all 12-hour average TRS concentrations to 10 volume percent oxygen, except that all 12-hour average TRS concentration from a recovery furnace shall be corrected to 8 volume percent using the following equation:

$$C_{corr}=C_{meas}\times(21-X/21-Y)$$

where:

C_{corr}=the concentration corrected for oxygen.
C_{meas}=the concentration uncorrected for oxygen.
X=the volumetric oxygen concentration in percentage to be corrected to (8 percent for recovery furnaces and 10 percent for lime kilns, incinerators, or other devices).
Y=the measured 12-hour average volumetric oxygen concentration.

(d) For the purpose of reports required under § 60.7(c), any owner or operator subject to the provisions of this subpart shall report periods of excess emissions as follows:

(1) For emissions from any recovery furnace periods of excess emissions are:

(i) All 12-hour averages of TRS concentrations above 5 ppm by volume for straight kraft recovery furnaces and above 25 ppm by volume for cross recovery furnaces.

(ii) All 6-minute average opacities that exceed 35 percent.

(2) For emissions from any lime kiln, periods of excess emissions are all 12-hour average TRS concentration above 8 ppm by volume.

(3) For emissions from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system periods of excess emissions are:

(i) All 12-hour average TRS concentrations above 5 ppm by volume unless the provisions of § 60.283(a)(1) (i), (ii), or (iv) apply; or

(ii) All periods in excess of 5 minutes and their duration during which the combustion temperature at the point of incineration is less than 1200° F, where the provisions of § 60.283(a)(1)(ii) apply.

(e) The Administrator will not consider periods of excess emissions reported under paragraph (d) of this section to be indicative of a violation of § 60.11(d) provided that:

(1) The percent of the total number of possible contiguous periods of excess emissions in a quarter (excluding periods of startup, shutdown, or malfunction and periods when the facility is not operating) during which excess emissions occur does not exceed:

(i) One percent for TRS emissions from recovery furnaces.

(ii) Six percent for average opacities from recovery furnaces.

(2) The Administrator determines that the affected facility, including air pollution control equipment, is maintained and operated in a manner which is consistent with good air pollution control practice for minimizing emissions during periods of excess emissions.

§ 60.285 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.282(a) as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) When determining compliance with § 60.282(a)(2), Method 2 for velocity and volumetric flow rate,

(4) Method 3 for gas analysis, and

(5) Method 9 for visible emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.85 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure outlined in Method 5.

(c) Method 17 (in-stack filtration) may be used as an alternate method for Method 5 for determining compliance with § 60.282(a)(1)(i): *Provided*, That a constant value of 0.009 g/dscm (0.004 gr/dscf) is added to the results of Method 17 and the stack temperature is no greater than 205° C (ca. 400° F). Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure outlined in Method 17.

(d) For the purpose of determining compliance with § 60.283(a) (1), (2), (3), (4), and (5), the following reference methods shall be used:

(1) Method 16 for the concentration of TRS,

(2) Method 3 for gas analysis, and

(3) When determining compliance with § 60.283(a)(4), use the results of Method 2, Method 16, and the black liquor solids feed rate in the following equation to determine the TRS emission rate.

$$E = (C_{H_2S}F_{H_2S} + C_{MeSH}F_{MeSH} + C_{DMS}F_{DMS} + C_{DMDS}F_{DMDS})(Q_{sd})/BLS$$

Where:

E = mass of TRS emitted per unity of black liquor solids (g/kg) (lb/ton)

C_{H_2S} = average concentration of hydrogen sulfide (H_2S) during the test period, PPM.

C_{MeSH} = average concentration of methyl mercaptan (MeSH) during the test period, PPM.

C_{DMS} = average concentration of dimethyl sulfide (DMS) during the test period, PPM.

C_{DMDS} = average concentration of dimethyl disulfide (DMDS) during the test period, PPM.

F_{H_2S} = 0.001417 g/m^3 PPM for metric units
= 0.08844 lb/ft^3 PPM for English units

F_{MeSH} = 0.00200 g/m^3 PPM for metric units
= 0.1248 lb/ft^3 PPM for English units

F_{DMS} = 0.002583 g/m^3 PPM for metric units
= 0.1612 lb/ft^3 PPM for English units

F_{DMDS} = 0.003917 g/m^3 PPM for metric units
= 0.2445 lb/ft^3 PPM for English units

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

BLS = black liquor solids feed rate, kg/hr (lb/hr)

(4) When determining whether a furnace is straight kraft recovery furnace or a cross recovery furnace, TAPPI Method T.624 shall be used to determine sodium sulfide, sodium hydroxide and sodium carbonate. These determinations shall be made three times daily from the green liquor and the daily average values shall be converted to sodium oxide (Na_2O) and substituted into the following equation to determine the green liquor sulfidity:

$$GLS = 100 \quad C_{Na_2S}/C_{Na_2S} + C_{NaOH} + C_{Na_2CO_3}$$

Where:

GLS = percent green liquor sulfidity

C_{Na_2S} = average concentration of Na_2S expressed as Na_2O (mg/1)

$C_{Na}OH$ = *average concentration of* $NaOH$ expressed as Na_2O (mg/1)

$C_{Na_2}CO_3$ = average concentration of Na_2CO_3 expressed as Na_2O (mg/1)

(e) All concentrations of particulate matter and TRS required to be measured by this section from lime kilns or incinerators shall be corrected 10 volume percent oxygen and those concentrations from recovery furnaces shall be corrected to 8 volume percent oxygen. These corrections shall be made in the manner specified in § 60.284(c)(3).

36 FR 24876, 12/23/71 (1)
as amended
43 FR 7568, 2/23/78 (82)
43 FR 34784, 8/7/78 (91)

Subpart DD—Standards of Performance for Grain Elevators [90]

§ 60.300 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility at any grain terminal elevator or any grain storage elevator, except as provided under § 60.304(b). The affected facilities are each truck unloading station, truck loading station, barge and ship unloading station, barge and ship loading station, railcar loading station, railcar unloading station, grain dryer, and all grain handling operations.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after (date of reinstatement of proposal) is subject to the requirements of this part.

§ 60.301 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the act and in subpart A of this part.

(a) "Grain" means corn, wheat, sorghum, rice, rye, oats, barley, and soybeans.

(b) "Grain elevator" means any plant or installation at which grain is unloaded, handled, cleaned, dried, stored, or loaded.

(c) "Grain terminal elevator" means any grain elevator which has a permanent storage capacity of more than 88,100 m³ (ca. 2.5 million U.S. bushels), except those located at animal food manufacturers, pet food manufacturers, cereal manufacturers, breweries, and livestock feedlots.

(d) "Permanent storage capacity" means grain storage capacity which is inside a building, bin, or silo.

(e) "Railcar" means railroad hopper car or boxcar.

(f) "Grain storage elevator" means any grain elevator located at any wheat flour mill, wet corn mill, dry corn mill (human consumption), rice mill, or soybean oil extraction plant which has a permanent grain storage capacity of 35,200 m³ (ca. 1 million bushels).

(g) "Process emission" means the particulate matter which is collected by a capture system.

(h) "Fugitive emission" means the particulate matter which is not collected by a capture system and is released directly into the atmosphere from an affected facility at a grain elevator.

(i) "Capture system" means the equipment such as sheds, hoods, ducts, fans, dampers, etc. used to collect particulate matter generated by an affected facility at a grain elevator.

(j) "Grain unloading station" means that portion of a grain elevator where the grain is transferred from a truck, railcar, barge, or ship to a receiving hopper.

(k) "Grain loading station" means that portion of a grain elevator where the grain is transferred from the elevator to a truck, railcar, barge, or ship.

(l) "Grain handling operations" include bucket elevators or legs (excluding legs used to unload barges or ships), scale hoppers and surge bins (garners), turn heads, scalpers, cleaners, trippers, and the headhouse and other such structures.

(m) "Column dryer" means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in one or more continuous packed columns between two perforated metal sheets.

(n) "Rack dryer" means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in a cascading flow around rows of baffles (racks).

(o) "Unloading leg" means a device which includes a bucket-type elevator which is used to remove grain from a barge or ship.

§ 60.302 Standard for particulate matter.

(a) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any gases which exhibit greater than 0 percent opacity from any:

(1) Column dryer with column plate perforation exceeding 2.4 mm diameter (ca. 0.094 inch).

(2) Rack dryer in which exhaust gases pass through a screen filter coarser than 50 mesh.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility except a grain dryer any process emission which:

(1) Contains particulate matter in excess of 0.023 g/dscm (ca. 0.01 gr/dscf).

(2) Exhibits greater than 0 percent opacity.

(c) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any fugitive emission from:

(1) Any individual truck unloading station, railcar unloading station, or railcar loading station, which exhibits greater than 5 percent opacity.

(2) Any grain handling operation which exhibits greater than 0 percent opacity.

(3) Any truck loading station which exhibits greater than 10 percent opacity.

(4) Any barge or ship loading station which exhibits greater than 20 percent opacity.

(d) The owner or operator of any barge or ship unloading station shall operate as follows:

(1) The unloading leg shall be enclosed from the top (including the receiving hopper) to the center line of the bottom pulley and ventilation to a control device shall be maintained on both sides of the leg and the grain receiving hopper.

(2) The total rate of air ventilated shall be at least 32.1 actual cubic meters per cubic meter of grain handling capacity (ca. 40 ft³/bu).

(3) Rather than meet the requirements of subparagraphs (1) and (2), of this paragraph the owner or operator may use other methods of emission control if it is demonstrated to the Administrator's satisfaction that they would reduce emissions of particulate matter to the same level or less.

§ 60.303 Test methods and procedures.

(a) Reference methods in appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with the standards prescribed under § 60.302 as follows:

(1) Method 5 or method 17 for concentration of particulate matter and associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate;

(4) Method 3 for gas analysis; and

(5) Method 9 for visible emissions.

(b) For method 5, the sampling probe and filter holder shall be operated without heaters. The sampling time for each run, using method 5 or method 17, shall be at least 60 minutes. The minimum sample volume shall be 1.7 dscm (ca. 60 dscf).

(Sec. 114, Clean Air Act, as amended (42 U.S.C. 7414).)

§ 60.304 Modifications.

(a) The factor 6.5 shall be used in place of "annual asset guidelines repair allowance percentage," to determine whether a capital expenditure as defined by § 60.2(bb) has been made to an existing facility.

(b) The following physical changes or changes in the method of operation shall not by themselves be considered a modification of any existing facility:

(1) The addition of gravity loadout spouts to existing grain storage or grain transfer bins.

(2) The installation of automatic grain weighing scales.

(3) Replacement of motor and drive units driving existing grain handling equipment.

(4) The installation of permanent storage capacity with no increase in hourly grain handling capacity.

36 FR 24876, 12/23/71 (1)
as amended
43 FR 34340, 8/3/78 (90)

90

Subpart HH—Standards of Performance for Lime Manufacturing Plants [85]

§ 60.340 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities used in the manufacture of lime: rotary lime kilns and lime hydrators.

(b) The provisions of this subpart are not applicable to facilities used in the manufacture of lime at kraft pulp mills.

(c) Any facility under paragraph (a) of this section that commences construction or modification after May 3, 1977, is subject to the requirements of this part.

§ 60.341 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in subpart A of this part.

(a) "Lime manufacturing plant" includes any plant which produces a lime product from limestone by calcination. Hydration of the lime product is also considered to be part of the source.

(b) "Lime product" means the product of the calcination process including, but not limited to, calcitic lime, dolomitic lime, and dead-burned dolomite.

(c) "Rotary lime kiln" means a unit with an inclined rotating drum which is used to produce a lime product from limestone by calcination.

(d) "Lime hydrator" means a unit used to produce hydrated lime product.

§ 60.342 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any rotary lime kiln any gases which:

(i) Contain particulate matter in excess of 0.15 kilogram per megagram of limestone feed (0.30 lb/ton).

(ii) Exhibit 10 percent opacity or greater.

(2) From any lime hydrator any gases which contain particulate matter in excess of 0.075 kilogram per megagram of lime feed (0.15 lb/ton).

§ 60.343 Monitoring of emissions and operations.

(a) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate a continuous monitoring system, except as provided in paragraph (b) of this section, to monitor and record the opacity of a representative portion of the gases discharged into the atmosphere from any rotary lime kiln. The span of this system shall be set at 40 percent opacity.

(b) The owner or operator of any rotary lime kiln using a wet scrubbing emission control device subject to the provisions of this subpart shall not be required to monitor the opacity of the gases discharged as required in paragraph (a) of this section, but shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be accurate within ±250 pascals (one inch of water).

(2) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control device. The monitoring device must be accurate within ±5 percent of design scrubbing liquid supply pressure.

(c) The owner or operator of any lime hydrator using a wet scrubbing emission control device subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measuring of the scrubbing liquid flow rate. The monitoring device must be accurate within ±5 percent of design scrubbing liquid flow rate.

(2) A monitoring device for the continuous measurement of the electric current, in amperes, used by the scrubber. The monitoring device must be accurate within ±10 percent over its normal operating range.

(d) For the purpose of conducting a performance test under § 60.8, the owner or operator of any lime manufacturing plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device for measuring the mass rate of limestone feed to any affected rotary lime kiln and the mass rate of lime feed to any affected lime hydrator. The measuring device used must be accurate to within ±5 percent of the mass rate over its operating range.

(e) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as all six-minute periods during which the average opacity of the plume from any lime kiln subject to paragraph (a) of this subpart is 10 percent or greater.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 7414).)

§ 60.344 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.322(a) as follows:

(1) Method 5 for the measurement of particulate matter,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate,

(4) Method 3 for gas analysis,

(5) Method 4 for stack gas moisture, and

(6) Method 9 for visible emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.85 std m^3/h, dry basis (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Because of the high moisture content (40 to 85 percent by volume) of the exhaust gases from hydrators, the Method 5 sample train may be modified to include a calibrated orifice immediately following the sample nozzle when testing lime hydrators. In this configuration, the sampling rate necessary for maintaining isokinetic conditions can be directly related to exhaust gas velocity without a correction for moisture content. Extra care should be exercised when cleaning the sample train with the orifice in this position following the test runs.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 7414).)

36 FR 24876, 12/23/71 (1)
as amended
43 FR 9452, 3/7/78 (85)

Appendix A—Reference Methods[8]

The reference methods in this appendix are referred to in § 60.8 (Performance Tests) and § 60.11 (Compliance With Standards and Maintenance Requirements) of 40 CFR Part 60, Subpart A (General Provisions). Specific uses of these reference methods are described in the standards of performance contained in the subparts, beginning with Subpart D. .

Within each standard of performance, a section titled "Test Methods and Procedures" is provided to (1) identify the test methods applicable to the facility subject to the respective standard and (2) identify any special instructions or conditions to be followed when applying a method to the respective facility. Such instructions (for example, establish sampling rates, volumes, or temperatures) are to be used either in addition to, or as a substitute for procedures in a reference method. Similarly, for sources subject to emission monitoring requirements, specific instructions pertaining to any use of a reference method are provided in the subpart or in Appendix B.

Inclusion of methods in this appendix is not intended as an endorsement or denial of their applicability to sources that are not subject to standards of performance. The methods are potentially applicable to other sources; however, applicability should be confirmed by careful and appropriate evaluation of the conditions prevalent at such sources.

The approach followed in the formulation of the reference methods involves specifications for equipment, procedures, and performance. In concept, a performance specification approach would be preferable in all methods because this allows the greatest flexibility to the user. In practice, however, this approach is impractical in most cases because performance specifications cannot be established. Most of the methods described herein, therefore, involve specific equipment specifications and procedures, and only a few methods in this appendix rely on performance criteria.

Minor changes in the reference methods should not necessarily affect the validity of the results and it is recognized that alternative and equivalent methods exist. Section 60.8 provides authority for the Administrator to specify or approve (1) equivalent methods, (2) alternative methods, and (3) minor changes in the methodology of the reference methods. It should be clearly understood that unless otherwise identified all such methods and changes must have prior approval of the Administrator. An owner employing such methods or deviations from the reference methods without obtaining prior approval does so at the risk of subsequent disapproval and retesting with approved methods.

Within the reference methods, certain specific equipment or procedures are recognized as being acceptable or potentially acceptable and are specifically identified in the methods. The items identified as acceptable options may be used without approval but must be identified in the test report. The potentially approvable options are cited as "subject to the approval of the Administrator" or as "or equivalent." Such potentially approvable techniques or alternatives may be used at the discretion of the owner without prior approval. However, detailed descriptions for applying these potentially approvable techniques or alternatives are not provided in the reference methods. Also, the potentially approvable options are not necessarily acceptable in all applications. Therefore, an owner electing to use such potentially approvable techniques or alternatives is responsible for: (1) assuring that the techniques or alternatives are in fact applicable and are properly executed; (2) including a written description of the alternative method in the test report (the written method must be clear and must be capable of being performed without additional instruction, and the degree of detail should be similar to the detail contained in the reference methods); and (3) providing any rationale or supporting data necessary to show the validity of the alternative in the particular application. Failure to meet these requirements can result in the Administrator's disapproval of the alternative.

69

METHOD 1—SAMPLE AND VELOCITY TRAVERSES FOR STATIONARY SOURCES 69

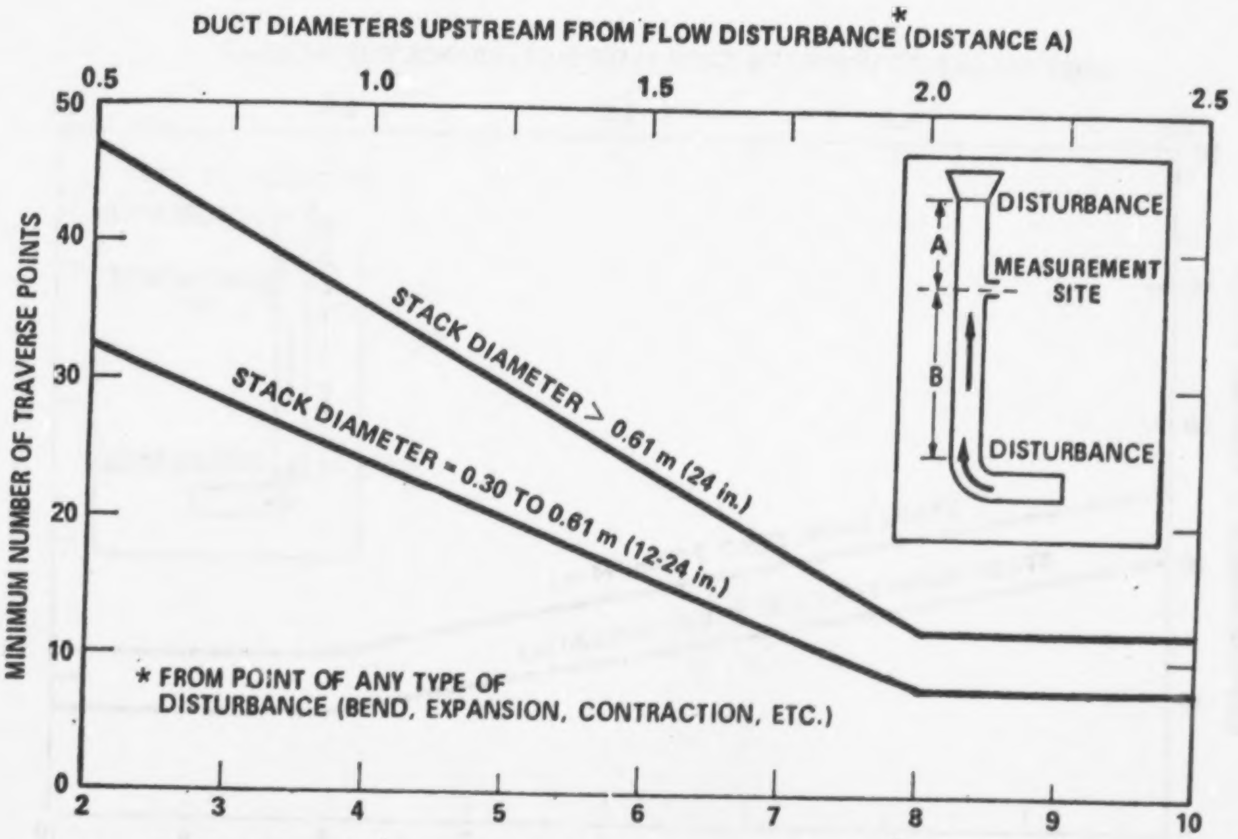

Figure 1-1. Minimum number of traverse points for particulate traverses.

1. *Principle and Applicability*

1.1 Principle. To aid in the representative measurement of pollutant emissions and/or total volumetric flow rate from a stationary source, a measurement site where the effluent stream is flowing in a known direction is selected, and the cross-section of the stack is divided into a number of equal areas. A traverse point is then located within each of these equal areas.

1.2 Applicability. This method is applicable to flowing gas streams in ducts, stacks, and flues. The method cannot be used when: (1) flow is cyclonic or swirling (see Section 2.4), (2) a stack is smaller than about 0.30 meter (12 in.) in diameter, or 0.071 m² (113 in.²) in cross-sectional area, or (3) the measurement site is less than two stack or duct diameters downstream or less than a half diameter upstream from a flow disturbance.

The requirements of this method must be considered before construction of a new facility from which emissions will be measured; failure to do so may require subsequent alterations to the stack or deviation from the standard procedure. Cases involving variants are subject to approval by the Administrator, U.S. Environmental Protection Agency.

2. *Procedure*

2.1 Selection of Measurement Site. Sampling or velocity measurement is performed at a site located at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion, or contraction in the stack, or from a visible flame. If necessary, an alternative location may be selected, at a position at least two stack or duct diameters downstream and a half diameter upstream from any flow disturbance. For a rectangular cross section, an equivalent diameter (D_e) shall be calculated from the following equation, to determine the upstream and downstream distances:

$$D_e=\frac{2LW}{L+W}$$

where L=length and W=width.

2.2 Determining the Number of Traverse Points.

2.2.1 Particulate Traverses. When the eight- and two-diameter criterion can be met, the minimum number of traverse points shall be: (1) twelve, for circular or rectangular stacks with diameters (or equivalent diameters) greater than 0.61 meter (24 in.); (2) eight, for circular stacks with diameters between 0.30 and 0.61 meter (12–24 in.); (3) nine, for rectangular stacks with equivalent diameters between 0.30 and 0.61 meter (12–24 in.).

When the eight- and two-diameter criterion cannot be met, the minimum number of traverse points is determined from Figure 1-1. Before referring to the figure, however, determine the distances from the chosen measurement site to the nearest upstream and downstream disturbances, and divide each distance by the stack diameter or equivalent diameter, to determine the distance in terms of the number of duct diameters. Then, determine from Figure 1-1 the minimum number of traverse points that corresponds: (1) to the number of duct diameters upstream; and (2) to the number of diameters downstream. Select the higher of the two minimum numbers of traverse points, or a greater value, so that for circular stacks the number is a multiple of 4, and for rectangular stacks, the number is one of those shown in Table 1-1.

TABLE 1-1. *Cross-sectional layout for rectangular stacks*

Number of traverse points: 87	*Matrix layout*
9	3x3
12	4x3
16	4x4
20	5x4
25	5x5
30	6x5
36	6x6
42	7x6
49	7x7

2.2.2 Velocity (Non-Particulate) Traverses. When velocity or volumetric flow rate is to be determined (but not particulate matter), the same procedure as that for particulate traverses (Section 2.2.1) is followed, except that Figure 1-2 may be used instead of Figure 1-1.

2.3 Cross-Sectional Layout and Location of Traverse Points.

2.3.1 Circular Stacks. Locate the traverse points on two perpendicular diameters according to Table 1-2 and the example shown in Figure 1-3. Any equation (for examples, see Citations 2 and 3 in the Bibliography) that gives the same values as those in Table 1-2 may be used in lieu of Table 1-2. 87

For particulate traverses, one of the diameters must be in a plane containing the greatest expected concentration variation, e.g., after bends, one diameter shall be in the plane of the bend. This requirement becomes less critical as the distance from the disturbance increases; therefore, other diameter locations may be used, subject to approval of the Administrator.

In addition, for stacks having diameters greater than 0.61 m (24 in.) no traverse points shall be located within 2.5 centimeters (1.00 in.) of the stack walls; and for stack diameters equal to or less than 0.61 m (24 in.), no traverse points shall be located within 1.3 cm (0.50 in.) of the stack walls. To meet these criteria, observe the procedures given below.

2.3.1.1 Stacks With Diameters Greater Than 0.61 m (24 in.). When any of the traverse points as located in Section 2.3.1 fall within 2.5 cm (1.00 in.) of the stack walls, relocate them away from the stack walls to: (1) a distance of 2.5 cm (1.00 in.); or (2) a distance equal to the nozzle inside diameter, whichever is larger. These relocated traverse points (on each end of a diameter) shall be the "adjusted" traverse points.

Whenever two successive traverse points are combined to form a single adjusted traverse point, treat the adjusted point as two separate traverse points, both in the sampling (or velocity measurement) procedure, and in recording the data.

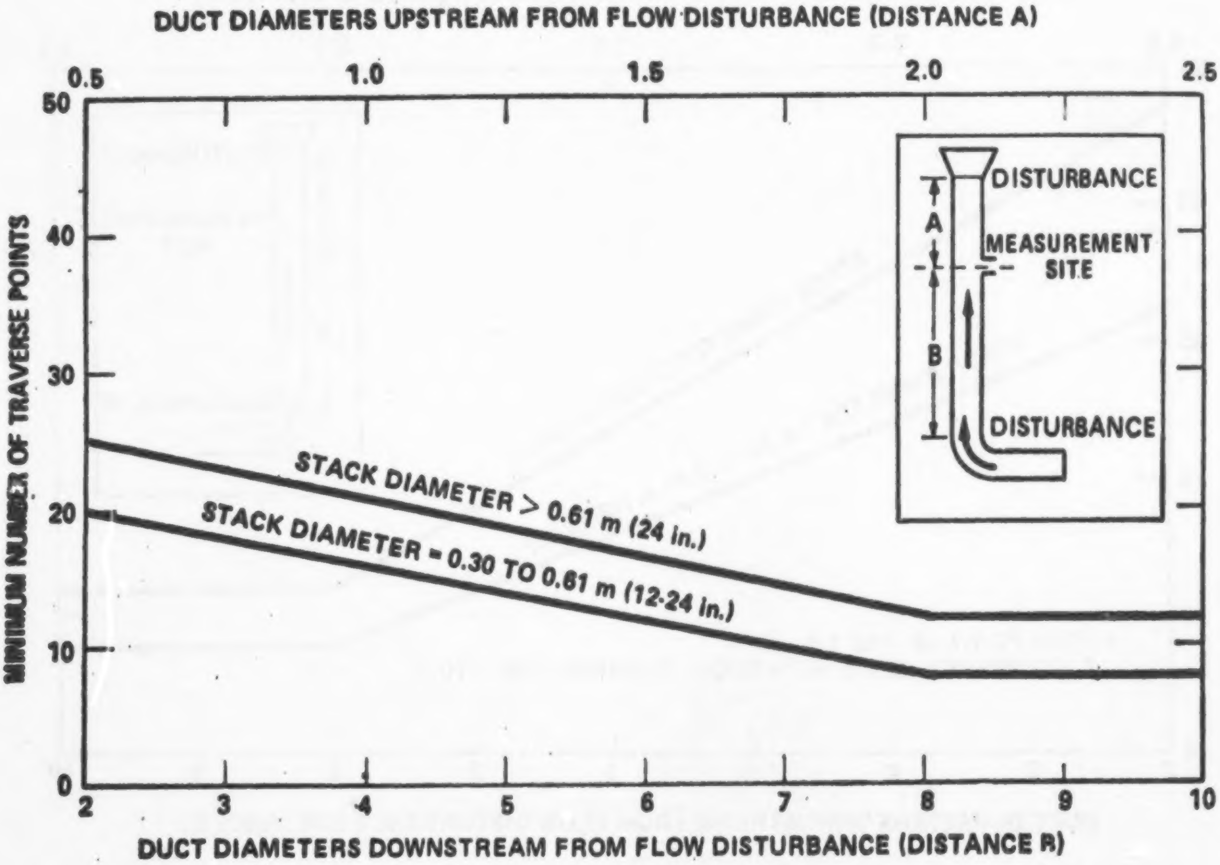

Figure 1-2. Minimum number of traverse points for velocity (nonparticulate) traverses.

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TRAVERSE POINT	DISTANCE, % of diameter
1	4.4
2	14.7
3	29.5
4	70.5
5	85.3
6	95.6

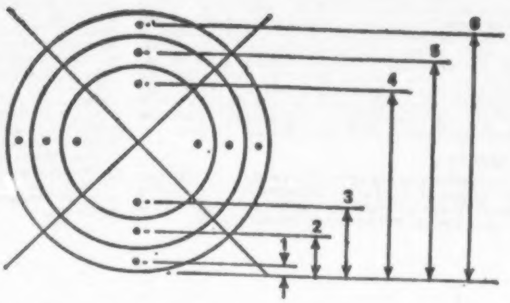

Figure 1-3. Example showing circular stack cross section divided into 12 equal areas, with location of traverse points indicated.

Table 1-2. LOCATION OF TRAVERSE POINTS IN CIRCULAR STACKS

(Percent of stack diameter from inside wall to traverse point)

Traverse point number on a diameter	Number of traverse points on a diameter											
	2	4	6	8	10	12	14	16	18	20	22	24
1	14.6	6.7	4.4	3.2	2.6	2.1	1.8	1.6	1.4	1.3	1.1	1.1
2	85.4	25.0	14.6	10.5	8.2	6.7	5.7	4.9	4.4	3.9	3.5	3.2
3		75.0	29.6	19.4	14.6	11.8	9.9	8.5	7.5	6.7	6.0	5.5
4		93.3	70.4	32.3	22.6	17.7	14.6	12.5	10.9	9.7	8.7	7.9
5			85.4	67.7	34.2	25.0	20.1	16.9	14.6	12.9	11.6	10.5
6			95.6	80.6	65.8	35.6	26.9	22.0	18.8	16.5	14.6	13.2
7				89.5	77.4	64.4	36.6	28.3	23.6	20.4	18.0	16.1
8				96.8	85.4	75.0	63.4	37.5	29.6	25.0	21.8	19.4
9					91.8	82.3	73.1	62.5	38.2	30.6	26.2	23.0
10					97.4	88.2	79.9	71.7	61.8	38.8	31.5	27.2
11						93.3	85.4	78.0	70.4	61.2	39.3	32.3
12						97.9	90.1	83.1	76.4	69.4	60.7	39.8
13							94.3	87.5	81.2	75.0	68.5	60.2
14							98.2	91.5	85.4	79.6	73.8	67.7
15								95.1	89.1	83.5	78.2	72.8
16								98.4	92.5	87.1	82.0	77.0
17									95.6	90.3	85.4	80.6
18									98.6	93.3	88.4	83.9
19										96.1	91.3	86.8
20										98.7	94.0	89.5
21											96.5	92.1
22											98.9	94.5
23												96.8
24												98.9

2.3.1.2 Stacks With Diameters Equal to or Less Than 0.61 m (24 in.). Follow the procedure in Section 2.3.1.1, noting only that any "adjusted" points should be relocated away from the stack walls to: (1) a distance of 1.3 cm (0.50 in.); or (2) a distance equal to the nozzle inside diameter, whichever is larger.

2.3.2 Rectangular Stacks. Determine the number of traverse points as explained in Sections 2.1 and 2.2 of this method. From Table 1-1, determine the grid configuration. Divide the stack cross-section into as many equal rectangular elemental areas as traverse points, and then locate a traverse point at the centroid of each equal area according to the example in Figure 1-4.

If the tester desires to use more than the minimum number of traverse points, expand the "minimum number of traverse points" matrix (see Table 1-1) by adding the extra traverse points along one or the other or both legs of the matrix; the final matrix need not be balanced. For example, if a 4x3 "minimum number of points" matrix were expanded to 36 points, the final matrix could be 9x4 or 12x3, and would not necessarily have to be 6x6. After constructing the final matrix, divide the stack cross-section into as many equal rectangular, elemental areas as traverse points, and locate a traverse point at the centroid of each equal area.87

The situation of traverse points being too close to the stack walls is not expected to arise with rectangular stacks. If this problem should ever arise, the Administrator must be contacted for resolution of the matter.

2.4 Verification of Absence of Cyclonic Flow. In most stationary sources, the direction of stack gas flow is essentially parallel to the stack walls. However, cyclonic flow may exist (1) after such devices as cyclones and inertial demisters following venturi scrubbers, or (2) in stacks having tangential inlets or other duct configurations which tend to induce swirling; in these instances, the presence or absence of cyclonic flow at the sampling location must be determined. The following techniques are acceptable for this determination.

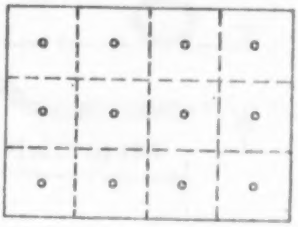

Figure 1-4. Example showing rectangular stack cross section divided into 12 equal areas, with a traverse point at centroid of each area.

Level and zero the manometer. Connect a Type S pitot tube to the manometer. Position the Type S pitot tube at each traverse point, in succession, so that the planes of the face openings of the pitot tube are perpendicular to the stack cross-sectional plane; when the Type S pitot tube is in this position, it is at "0° reference." Note the differential pressure (Δp) reading at each traverse point. If a null (zero) pitot reading is obtained at 0° reference at a given traverse point, an acceptable flow condition exists at that point. If the pitot reading is not zero at 0° reference, rotate the pitot tube (up to ±90° yaw angle), until a null reading is obtained. Carefully determine and record the value of the rotation angle (α) to the nearest degree. After the null technique has been applied at each traverse point, calculate the average of the absolute values of α; assign α values of 0° to those points for which no rotation was required, and include these in the overall average. If the average value of α is greater than 10°, the overall flow condition in the stack is unacceptable and alternative methodology, subject to the approval of the Administrator, must be used to perform accurate sample and velocity traverses.87

3. *Bibliography*

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4. Standard Method for Sampling Stacks for Particulate Matter. In: 1971 Book of ASTM Standards, Part 23. ASTM Designation D-2928-71. Philadelphia, Pa. 1971.

5. Hanson, H. A., et al. Particulate Sampling Strategies for Large Power Plants Including Nonuniform Flow. USEPA, ORD, ESRL, Research Triangle Park, N.C. EPA-600/2-76-170. June 1976.

6. Entropy Environmentalists, Inc. Determination of the Optimum Number of Sampling Points: An Analysis of Method 1 Criteria. Environmental Protection Agency. Research Triangle Park, N.C. EPA Contract No. 68-01-3172, Task 7.

METHOD 2—DETERMINATION OF STACK GAS VELOCITY AND VOLUMETRIC FLOW RATE (TYPE S PITOT TUBE)

1. *Principle and Applicability*

1.1 Principle. The average gas velocity in a stack is determined from the gas density and from measurement of the average velocity head with a Type S (Stausscheibe or reverse type) pitot tube.

1.2 Applicability. This method is applicable for measurement of the average velocity of a gas stream and for quantifying gas flow.

This procedure is not applicable at measurement sites which fail to meet the criteria of Method 1, Section 2.1. Also, the method cannot be used for direct measurement in cyclonic or swirling gas streams; Section 2.4 of Method 1 shows how to determine cyclonic or swirling flow conditions. When unacceptable conditions exist, alternative procedures, subject to the approval of the Administrator, U.S. Environmental Protection Agency, must be employed to make accurate flow rate determinations; examples of such alternative procedures are: (1) to install straightening vanes; (2) to calculate the total volumetric flow rate stoichiometrically, or (3) to move to another measurement site at which the flow is acceptable.

2. *Apparatus*

Specifications for the apparatus are given below. Any other apparatus that has been demonstrated (subject to approval of the Administrator) to be capable of meeting the specifications will be considered acceptable.

2.1 Type S Pitot Tube. The Type S pitot tube (Figure 2-1) shall be made of metal tubing (e.g., stainless steel). It is recommended that the external tubing diameter (dimension D_t, Figure 2-2b) be between 0.48 and 0.95 centimeters ($^3/_{16}$ and $^3/_8$ inch). There shall be an equal distance from the base of each leg of the pitot tube to its face-opening plane (dimensions P_A and P_B, Figure 2-2b); it is recommended that this distance be between 1.05 and 1.50 times the external tubing diameter. The face openings of the pitot tube shall, preferably, be aligned as shown in Figure 2-2; however, slight misalignments of the openings are permissible (see Figure 2-3).

The Type S pitot tube shall have a known coefficient, determined as outlined in Section 4. An identification number shall be assigned to the pitot tube; this number shall be permanently marked or engraved on the body of the tube.

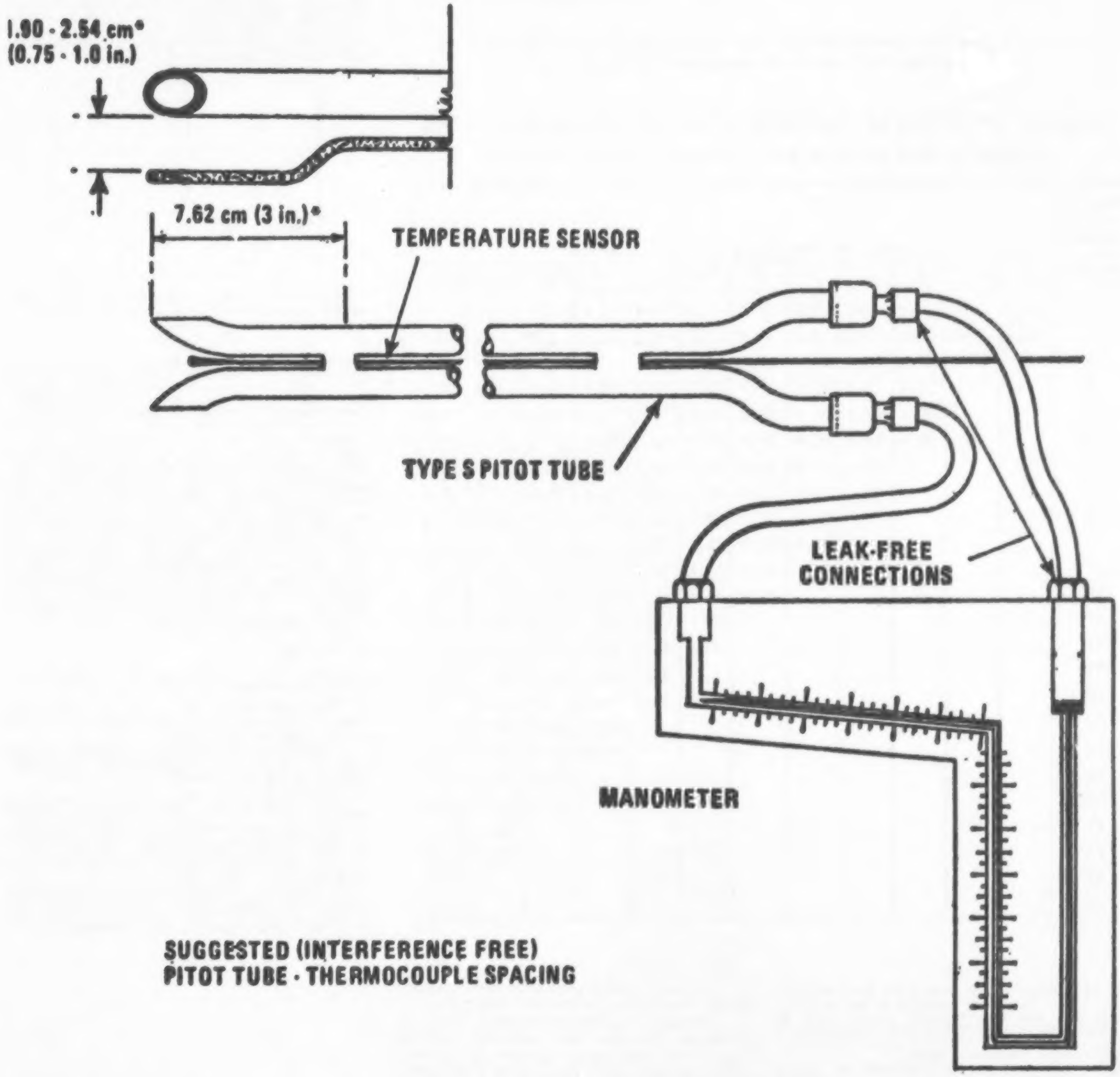


Figure 2-1. Type S pitot tube manometer assembly.

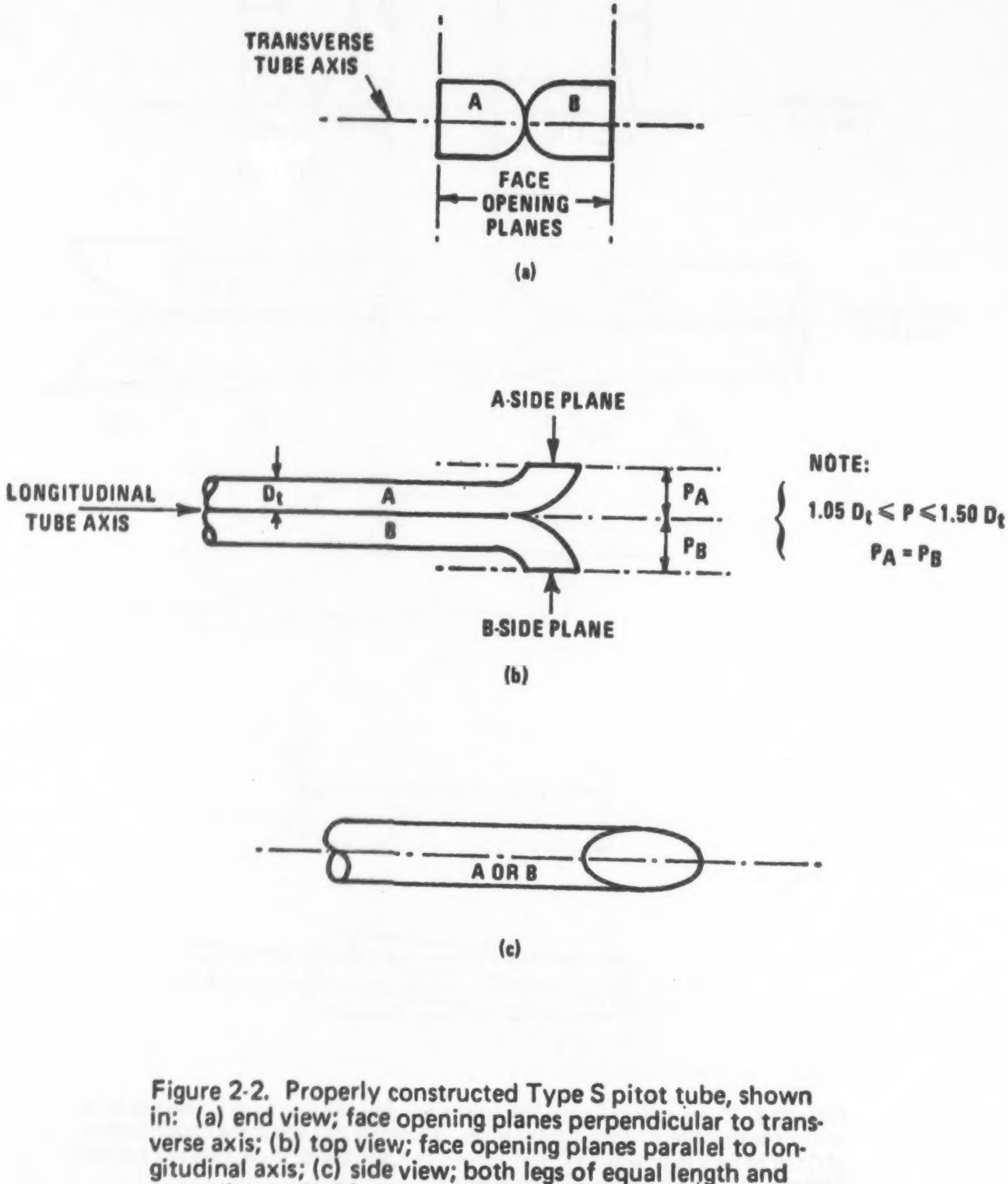

TRANSVERSE TUBE AXIS
A
B
FACE OPENING PLANES
(a)
A-SIDE PLANE
LONGITUDINAL TUBE AXIS
D_t
A
B
P_A
P_B
NOTE:
$1.05\ D_t \leq P \leq 1.50\ D_t$
$P_A = P_B$
B-SIDE PLANE
(b)
A OR B
(c)

Figure 2-2. Properly constructed Type S pitot tube, shown in: (a) end view; face opening planes perpendicular to transverse axis; (b) top view; face opening planes parallel to longitudinal axis; (c) side view; both legs of equal length and centerlines coincident, when viewed from both sides. Baseline coefficient values of 0.84 may be assigned to pitot tubes constructed this way.

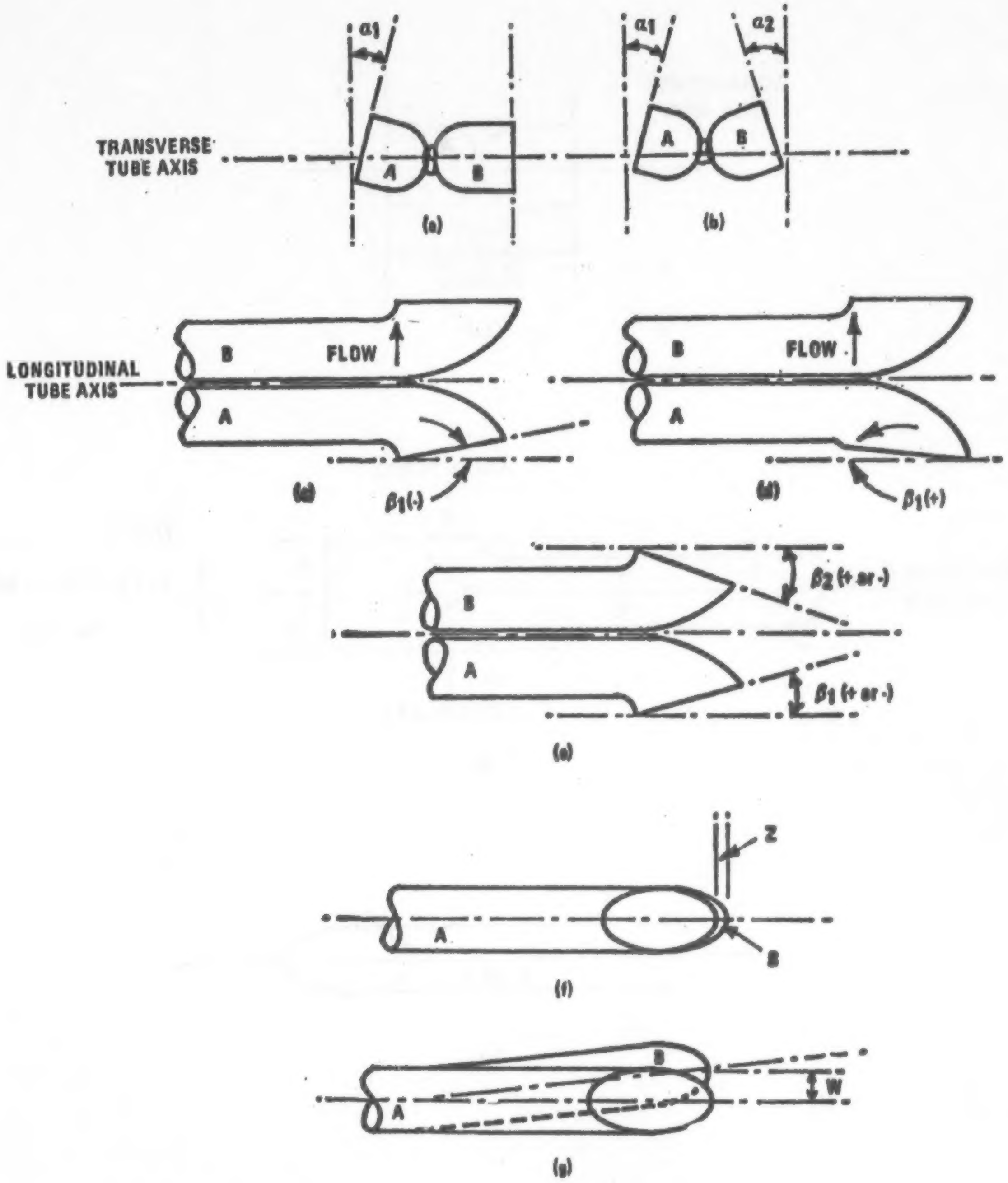

α1
α2
TRANSVERSE TUBE AXIS
A
B
(a)
(b)
LONGITUDINAL TUBE AXIS
B
A
FLOW
(c)
(d)
β1(-)
β1(+)
β2 (+ or -)
β1 (+ or -)
(e)
Z
A
B
(f)
W
(g)

Figure 2-3. Types of face-opening misalignment that can result from field use or improper construction of Type S pitot tubes. These will not affect the baseline value of $\bar{C}_{p(s)}$ so long as α_1 and $\alpha_2 < 10^{\circ}$, β_1 and $\beta_2 < 5^{\circ}$. $z < 0.32$ cm (1/8 in.) and $w < 0.08$ cm (1/32 in.) (citation 11 in Section 6).

A standard pitot tube may be used instead of a Type S, provided that it meets the specifications of Sections 2.7 and 4.2; note, however, that the static and impact pressure holes of standard pitot tubes are susceptible to plugging in particulate-laden gas streams. Therefore, whenever a standard pitot tube is used to perform a traverse, adequate proof must be furnished that the openings of the pitot tube have not plugged up during the traverse period; this can be done by taking a velocity head (Δp) reading at the final traverse point, cleaning out the impact and static holes of the standard pitot tube by "back-purging" with pressurized air, and then taking another Δp reading. If the Δp readings made before and after the air purge are the same (±5 percent), the traverse is acceptable. Otherwise, reject the run. Note that if Δp at the final traverse point is unsuitably low, another point may be selected. If "back-purging" at regular intervals is part of the procedure, then comparative Δp readings shall be taken, as above, for the last two back purges at which suitably high Δp readings are observed. 87

2.2 Differential Pressure Gauge. An inclined manometer or equivalent device is used. Most sampling trains are equipped with a 10-in. (water column) inclined-vertical manometer, having 0.01-in. H_2O divisions on the 0- to 1-in. inclined scale, and 0.1-in. H_2O divisions on the 1- to 10-in. vertical scale. This type of manometer (or other gauge of equivalent sensitivity) is satisfactory for the measurement of Δp values as low as 1.3 mm (0.05 in.) H_2O. However, a differential pressure gauge of greater sensitivity shall be used (subject to the approval of the Administrator), if any of the following is found to be true: (1) the arithmetic average of all Δp readings at the traverse points in the stack is less than 1.3 mm (0.05 in.) H_2O; (2) for traverses of 12 or more points, more than 10 percent of the individual Δp readings are below 1.3 mm (0.05 in.) H_2O; (3) for traverses of fewer than 12 points, more than one Δp reading is below 1.3 mm (0.05 in.) H_2O. Citation 18 in Section 6 describes commercially available instrumentation for the measurement of low-range gas velocities. 87

As an alternative to criteria (1) through (3) above, the following calculation may be performed to determine the necessity of using a more sensitive differential pressure gauge:

$$T=\frac{\sum_{i=1}^{n}\sqrt{\Delta p_i+K}}{\sum_{i=1}^{n}\sqrt{\Delta p_i}}$$

where:

Δp_i=Individual velocity head reading at a traverse point, mm H_2O (in. H_2O).

n=Total number of traverse points.

K=0.13 mm H_2O when metric units are used and 0.005 in H_2O when English units are used.

If T is greater than 1.05, the velocity head data are unacceptable and a more sensitive differential pressure gauge must be used.

NOTE.—If differential pressure gauges other than inclined manometers are used (e.g., magnehelic gauges), their calibration must be checked after each test series. To check the calibration of a differential pressure gauge, compare Δp readings of the gauge with those of a gauge-oil manometer at a minimum of three points, approximately representing the range of Δp values in the stack. If, at each point, the values of Δp as read by the differential pressure gauge and gauge-oil manometer agree to within 5 percent, the differential pressure gauge shall be considered to be in proper calibration. Otherwise, the test series shall either be voided, or procedures to adjust the measured Δp values and final results shall be used, subject to the approval of the Administrator.

2.3 Temperature Gauge. A thermocouple, liquid-filled bulb thermometer, bimetallic thermometer, mercury-in-glass thermometer, or other gauge capable of measuring temperature to within 1.5 percent of the minimum absolute stack temperature shall be used. The temperature gauge shall be attached to the pitot tube such that the sensor tip does not touch any metal; the gauge shall be in an interference-free arrangement with respect to the pitot tube face openings (see Figure 2-1 and also Figure 2-7 in Section 4). Alternate positions may be used if the pitot tube-temperature gauge system is calibrated according to the procedure of Section 4. Provided that a difference of not more than 1 percent in the average velocity measurement is introduced, the temperature gauge need not be attached to the pitot tube; this alternative is subject to the approval of the Administrator.

2.4 Pressure Probe and Gauge. A piezometer tube and mercury- or water-filled U-tube manometer capable of measuring stack pressure to within 2.5 mm (0.1 in.) Hg is used. The static tap of a standard type pitot tube or one leg of a Type S pitot tube with the face opening planes positioned parallel to the gas flow may also be used as the pressure probe. 87

2.5 Barometer. A mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg) may be used. In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm (0.1 in.) Hg per 30-meter (100 foot) elevation increase, or vice-versa for elevation decrease.

2.6 Gas Density Determination Equipment. Method 3 equipment, if needed (see Section 3.6), to determine the stack gas dry molecular weight, and Reference Method 4 or Method 5 equipment for moisture content determination; other methods may be used subject to approval of the Administrator.

2.7 Calibration Pitot Tube. When calibration of the Type S pitot tube is necessary (see Section 4), a standard pitot tube is used as a reference. The standard pitot tube shall, preferably, have a known coefficient, obtained either (1) directly from the National Bureau of Standards, Route 270, Quince Orchard Road, Gaithersburg, Maryland, or (2) by calibration against another standard pitot tube with an NBS-traceable coefficient. Alternatively, a standard pitot tube designed according to the criteria given in 2.7.1 through 2.7.5 below and illustrated in Figure 2-4 (see also Citations 7, 8, and 17 in Section 6) may be used. Pitot tubes designed according to these specifications will have baseline coefficients of about 0.99±0.01.

2.7.1 Hemispherical (shown in Figure 2-4), ellipsoidal, or conical tip.

2.7.2 A minimum of six diameters straight run (based upon D, the external diameter of the tube) between the tip and the static pressure holes.

2.7.3 A minimum of eight diameters straight run between the static pressure holes and the centerline of the external tube, following the 90 degree bend.

2.7.4 Static pressure holes of equal size (approximately 0.1 D), equally spaced in a piezometer ring configuration.

2.7.5 Ninety degree bend, with curved or mitered junction.

2.8 Differential Pressure Gauge for Type S Pitot Tube Calibration. An inclined manometer or equivalent is used. If the single-velocity calibration technique is employed (see Section 4.1.2.3), the calibration differential pressure gauge shall be readable to the nearest 0.13 mm H_2O (0.005 in. H_2O). For multivelocity calibrations, the gauge shall be readable to the nearest 0.13 mm H_2O (0.005 in H_2O) for Δp values between 1.3 and 25 mm H_2O (0.05 and 1.0 in. H_2O), and to the nearest 1.3 mm H_2O (0.05 in. H_2O) for Δp values above 25 mm H_2O (1.0 in. H_2O). A special, more sensitive gauge will be required to read Δp values below 1.3 mm H_2O [0.05 in. H_2O] (see Citation 18 in Section 6).

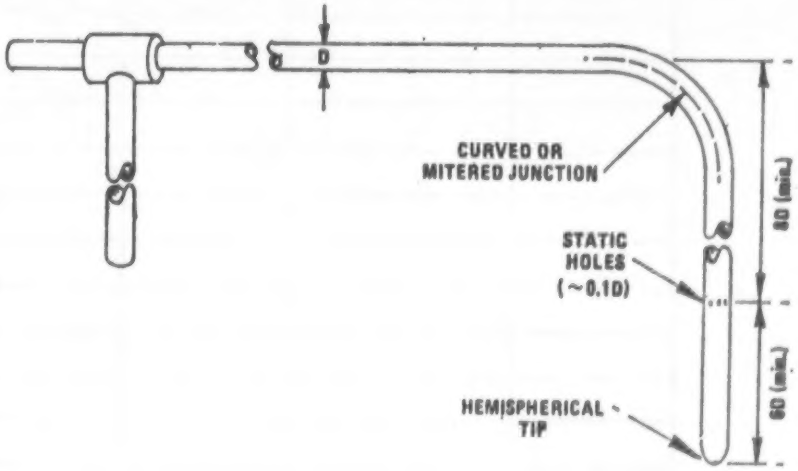


Figure 2-4. Standard pitot tube design specifications.

3. *Procedure*

3.1 Set up the apparatus as shown in Figure 2-1. Capillary tubing or surge tanks installed between the manometer and pitot tube may be used to dampen Δp fluctuations. It is recommended, but not required, that a pretest leak-check be conducted, as follows: (1) blow through the pitot impact opening until at least 7.6 cm (3 in.) H_2O velocity pressure registers on the manometer; then, close off the impact opening. The pressure shall remain stable for at least 15 seconds; (2) do the same for the static pressure side, except using suction to obtain the minimum of 7.6 cm (3 in.) H_2O. Other leak-check procedures, subject to the approval of the Administrator, may be used.

3.2 Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse. Record all necessary data as shown in the example data sheet (Figure 2-5). 87

3.3 Measure the velocity head and temperature at the traverse points specified by Method 1. Ensure that the proper differential pressure gauge is being used for the range of Δp values encountered (see Section 2.2). If it is necessary to change to a more sensitive gauge, do so, and remeasure the Δp and temperature readings at each traverse point. Conduct a post-test leak-check (mandatory), as described in Section 3.1 above, to validate the traverse run.

3.4 Measure the static pressure in the stack. One reading is usually adequate.

3.5 Determine the atmospheric pressure.

PLANT ______________________________

DATE ______________ RUN NO. ______________

STACK DIAMETER OR DIMENSIONS, m(in.) ______________

BAROMETRIC PRESSURE, mm Hg (in. Hg) ______________

CROSS SECTIONAL AREA, m^2 (ft^2) ______________

OPERATORS ______________________________

PITOT TUBE I.D. NO. ______________________________

AVG. COEFFICIENT, C_p = ______________

LAST DATE CALIBRATED ______________

SCHEMATIC OF STACK CROSS SECTION

Traverse Pt. No.	Vel. Hd., Δp mm (in.) H_2O	Stack Temperature		P_g mm Hg (in.Hg)	$\sqrt{\Delta p}$
		t_s, °C (°F)	T_s, °K (°R)		
		Average			

Figure 2-5. Velocity traverse data.

3.6 Determine the stack gas dry molecular weight. For combustion processes or processes that emit essentially CO_2, O_2, CO, and N_2, use Method 3. For processes emitting essentially air, an analysis need not be conducted; use a dry molecular weight of 29.0. For other processes, other methods, subject to the approval of the Administrator, must be used.

3.7 Obtain the moisture content from Reference Method 4 (or equivalent) or from Method 5.

3.8 Determine the cross-sectional area of the stack or duct at the sampling location. Whenever possible, physically measure the stack dimensions rather than using blueprints.

4. *Calibration*

4.1 Type S Pitot Tube. Before its initial use, carefully examine the Type S pitot tube in top, side, and end views to verify that the face openings of the tube are aligned within the specifications illustrated in Figure 2-2 or 2-3. The pitot tube shall not be used if it fails to meet these alignment specifications.

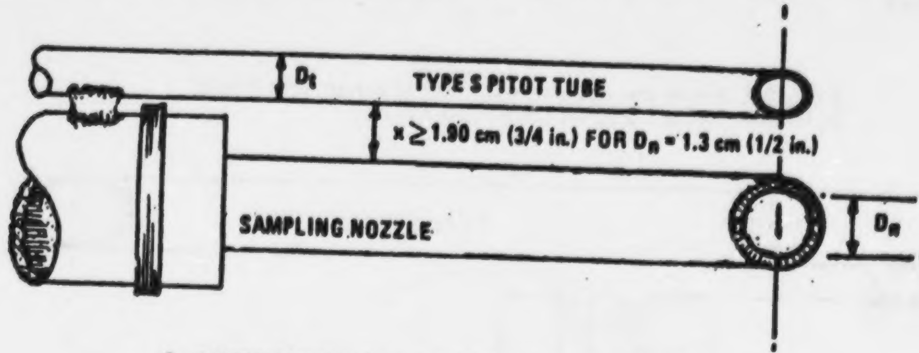
After verifying the face opening alignment, measure and record the following dimensions of the pitot tube: (a) the external tubing diameter (dimension D_t, Figure 2-2b); and (b) the base-to-opening plane distances (dimensions P_A and P_B, Figure 2-2b). If D_t is between 0.48 and 0.95 cm (3/16 and 3/8 in.) and if P_A and P_B are equal and between 1.05 and 1.50 D_t, there are two possible options: (1) the pitot tube may be calibrated according to the procedure outlined in Sections 4.1.2 through 4.1.5 below, or (2) a baseline (isolated tube) coefficient value of 0.84 may be assigned to the pitot tube. Note, however, that if the pitot tube is part of an assembly, calibration may still be required, despite knowledge of the baseline coefficient value (see Section 4.1.1). 37

If D_t, P_A, and P_B are outside the specified limits, the pitot tube must be calibrated as outlined in 4.1.2 through 4.1.5 below.

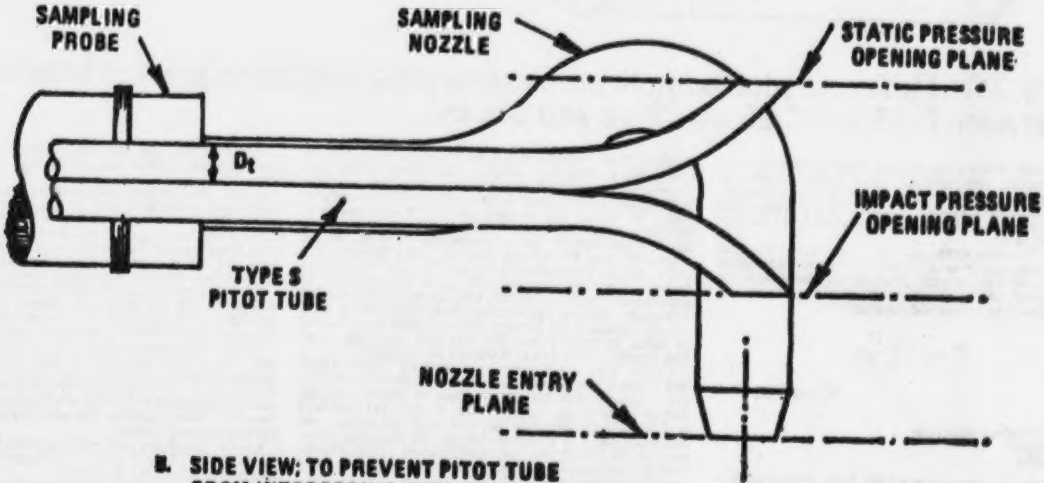
4.1.1 Type S Pitot Tube Assemblies. During sample and velocity traverses, the isolated Type S pitot tube is not always used; in many instances, the pitot tube is used in combination with other source-sampling components (thermocouple, sampling probe, nozzle) as part of an "assembly." The presence of other sampling components can sometimes affect the baseline value of the Type S pitot tube coefficient (Citation 9 in Section 6); therefore an assigned (or otherwise known) baseline coefficient value may or may not be valid for a given assembly. The baseline and assembly coefficient values will be identical only when the relative placement of the components in the assembly is such that aerodynamic interference effects are eliminated. Figures 2-6 through 2-8 illustrate interference-free component arrangements for Type S pitot tubes having external tubing diameters between 0.48 and 0.95 cm (3/16 and 3/8 in.). Type S pitot tube assemblies that fail to meet any or all of the specifications of Figures 2-6 through 2-8 shall be calibrated according to the procedure outlined in Sections 4.1.2 through 4.1.5 below, and prior to calibration, the values of the intercomponent spacings (pitot-nozzle, pitot-thermocouple, pitot-probe sheath) shall be measured and recorded.

NOTE.—Do not use any Type S pitot tube assembly which is constructed such that the impact pressure opening plane of the pitot tube is below the entry plane of the nozzle (see Figure 2-6b).

4.1.2 Calibration Setup. If the Type S pitot tube is to be calibrated, one leg of the tube shall be permanently marked A, and the other, B. Calibration shall be done in a flow system having the following essential design features: 37



A. BOTTOM VIEW; SHOWING MINIMUM PITOT-NOZZLE SEPARATION.



B. SIDE VIEW; TO PREVENT PITOT TUBE FROM INTERFERING WITH GAS FLOW STREAMLINES APPROACHING THE NOZZLE, THE IMPACT PRESSURE OPENING PLANE OF THE PITOT TUBE SHALL BE EVEN WITH OR ABOVE THE NOZZLE ENTRY PLANE.

Figure 2-6. Proper pitot tube - sampling nozzle configuration to prevent aerodynamic interference; buttonhook - type nozzle; centers of nozzle and pitot opening aligned; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

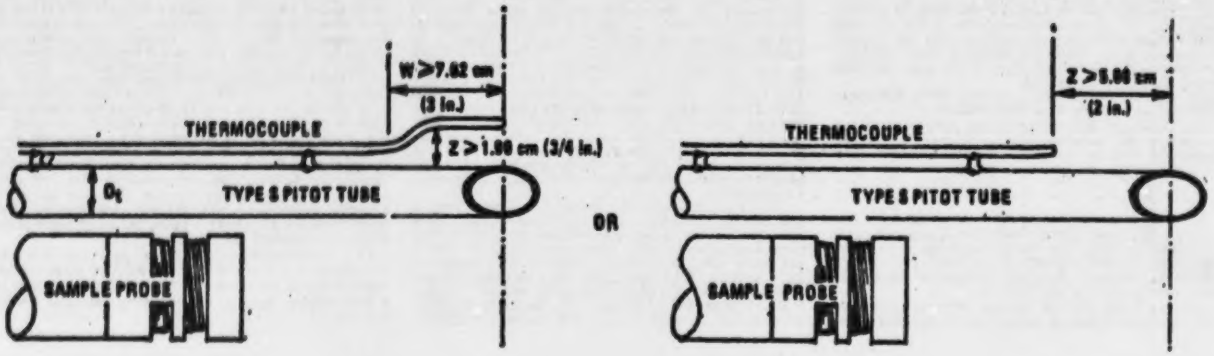


Figure 2-7. Proper thermocouple placement to prevent interference; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

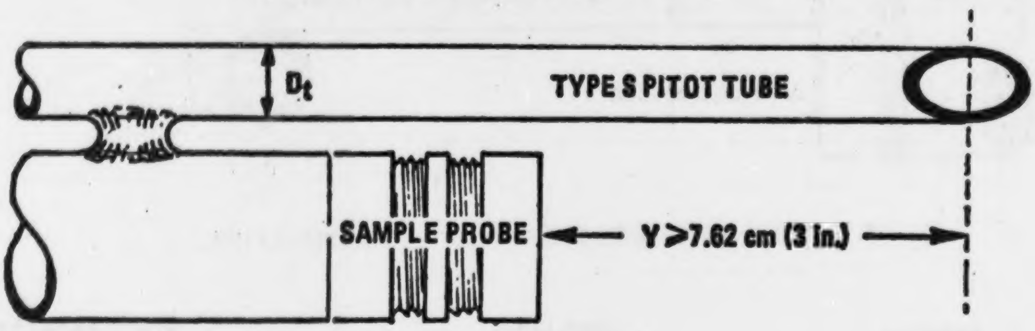


Figure 2-8. Minimum pitot-sample probe separation needed to prevent interference; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

4.1.2.1 The flowing gas stream must be confined to a duct of definite cross-sectional area, either circular or rectangular. For circular cross-sections, the minimum duct diameter shall be 30.5 cm (12 in.); for rectangular cross-sections, the width (shorter side) shall be at least 25.4 cm (10 in.).

4.1.2.2 The cross-sectional area of the calibration duct must be constant over a distance of 10 or more duct diameters. For a rectangular cross-section, use an equivalent diameter, calculated from the following equation, to determine the number of duct diameters:

$$D_e = \frac{2LW}{(L+W)}$$

Equation 2-1

where:
D_e = Equivalent diameter
L = Length
W = Width

To ensure the presence of stable, fully developed flow patterns at the calibration site, or "test section," the site must be located at least eight diameters downstream and two diameters upstream from the nearest disturbances.

NOTE.—The eight- and two-diameter criteria are not absolute; other test section locations may be used (subject to approval of the Administrator), provided that the flow at the test site is stable and demonstrably parallel to the duct axis.

4.1.2.3 The flow system shall have the capacity to generate a test-section velocity around 915 m/min (3,000 ft/min). This velocity must be constant with time to guarantee steady flow during calibration. Note that Type S pitot tube coefficients obtained by single-velocity calibration at 915 m/min (3,000 ft/min) will generally be valid to within ±3 percent for the measurement of velocities above 305 m/min (1,000 ft/min) and to within ±5 to 6 percent for the measurement of velocities between 180 and 305 m/min (600 and 1,000 ft/min). If a more precise correlation between C_p and velocity is desired, the flow system shall have the capacity to generate at least four distinct, time-invariant test-section velocities covering the velocity range from 180 to 1,525 m/min (600 to 5,000 ft/min), and calibration data shall be taken at regular velocity intervals over this range (see Citations 9 and 14 in Section 6 for details).

4.1.2.4 Two entry ports, one each for the standard and Type S pitot tubes, shall be cut in the test section; the standard pitot entry port shall be located slightly downstream of the Type S port, so that the standard and Type S impact openings will lie in the same cross-sectional plane during calibration. To facilitate alignment of the pitot tubes during calibration, it is advisable that the test section be constructed of plexiglas or some other transparent material.

4.1.3 Calibration Procedure. Note that this procedure is a general one and must not be used without first referring to the special considerations presented in Section 4.1.5. Note also that this procedure applies only to single-velocity calibration. To obtain calibration data for the A and B sides of the Type S pitot tube, proceed as follows:

4.1.3.1 Make sure that the manometer is properly filled and that the oil is free from contamination and is of the proper density. Inspect and leak-check all pitot lines; repair or replace if necessary.

4.1.3.2 Level and zero the manometer. Turn on the fan and allow the flow to stabilize. Seal the Type S entry port.

4.1.3.3 Ensure that the manometer is level and zeroed. Position the standard pitot tube at the calibration point (determined as outlined in Section 4.1.5.1), and align the tube so that its tip is pointed directly into the flow. Particular care should be taken in aligning the tube to avoid yaw and pitch angles. Make sure that the entry port surrounding the tube is properly sealed.

4.1.3.4 Read Δp_{std} and record its value in a data table similar to the one shown in Figure 2-9. Remove the standard pitot tube from the duct and disconnect it from the manometer. Seal the standard entry port.

4.1.3.5 Connect the Type S pitot tube to the manometer. Open the Type S entry port. Check the manometer level and zero. Insert and align the Type S pitot tube so that its A side impact opening is at the same point as was the standard pitot tube and is pointed directly into the flow. Make sure that the entry port surrounding the tube is properly sealed.

4.1.3.6 Read Δp_s and enter its value in the data table. Remove the Type S pitot tube from the duct and disconnect it from the manometer.

4.1.3.7 Repeat steps 4.1.3.3 through 4.1.3.6 above until three pairs of Δp readings have been obtained.

4.1.3.8 Repeat steps 4.1.3.3 through 4.1.3.7 above for the B side of the Type S pitot tube.

4.1.3.9 Perform calculations, as described in Section 4.1.4 below.

4.1.4 Calculations.

4.1.4.1 For each of the six pairs of Δp readings (i.e., three from side A and three from side B) obtained in Section 4.1.3 above, calculate the value of the Type S pitot tube coefficient as follows:

PITOT TUBE IDENTIFICATION NUMBER: ______________ **DATE:** __________

CALIBRATED BY: ______________________________

	"A" SIDE CALIBRATION			
RUN NO.	Δp_{std} cm H_2O (in. H_2O)	$\Delta p_{(s)}$ cm H_2O (in. H_2O)	$C_{p(s)}$	DEVIATION $C_{p(s)} - \bar{C}_p(A)$
1				
2				
3				
		$\bar{C}_p$ (SIDE A)		

	"B" SIDE CALIBRATION			
RUN NO.	Δp_{std} cm H_2O (in. H_2O)	$\Delta p_{(s)}$ cm H_2O (in. H_2O)	$C_{p(s)}$	DEVIATION $C_{p(s)} - \bar{C}_p(B)$
1				
2				
3				
		$\bar{C}_p$ (SIDE B)		

$$\text{AVERAGE DEVIATION} = \sigma\,(\text{A OR B}) = \frac{\sum_{1}^{3} \left| C_{p(s)} - \bar{C}_p(\text{A OR B}) \right|}{3} \longleftarrow \text{MUST BE} < 0.01$$

$$\left| \bar{C}_p\,(\text{SIDE A}) - \bar{C}_p\,(\text{SIDE B}) \right| \longleftarrow \text{MUST BE} < 0.01$$

Figure 2-9. Pitot tube calibration data.

$$C_{p(s)} = C_{p(std)} \sqrt{\frac{\Delta p_{std}}{\Delta p_s}}$$

Equation 2-2

where:

$C_{p(s)}$ = Type S pitot tube coefficient 87

$C_{p(std)}$ = Standard pitot tube coefficient; use 0.99 if the coefficient is unknown and the tube is designed according to the criteria of Sections 2.7.1 to 2.7.5 of this method.

Δp_{std} = Velocity head measured by the standard pitot tube, cm H_2O (in. H_2O)

Δp_s = Velocity head measured by the Type S pitot tube, cm H_2O (in. H_2O)

4.1.4.2 Calculate $\bar{C}_p$ (side A), the mean A-side coefficient, and $\bar{C}_p$ (side B), the mean B-side coefficient; calculate the difference between these two average values.

4.1.4.3 Calculate the deviation of each of the three A-side values of $C_{p(s)}$ from $\bar{C}_p$ (side A), and the deviation of each B-side value of $C_{p(s)}$ from $\bar{C}_p$ (side B). Use the following equation:

$$\text{Deviation} = C_{p(s)} - \bar{C}_p(\text{A or B})$$

Equation 2-3

4.1.4.4 Calculate σ, the average deviation from the mean, for both the A and B sides of the pitot tube. Use the following equation:

$$\sigma\,(\text{side A or B}) = \frac{\sum_{1}^{3} \left| C_{p(s)} - \bar{C}_p(A \text{ or } B) \right|}{3}$$

Equation 2-4

4.1.4.5 Use the Type S pitot tube only if the values of σ (side A) and σ (side B) are less than or equal to 0.01 and if the absolute value of the difference between $\bar{C}_p$ (A) and $\bar{C}_p$ (B) is 0.01 or less.

4.1.5 Special considerations.

4.1.5.1 Selection of calibration point.

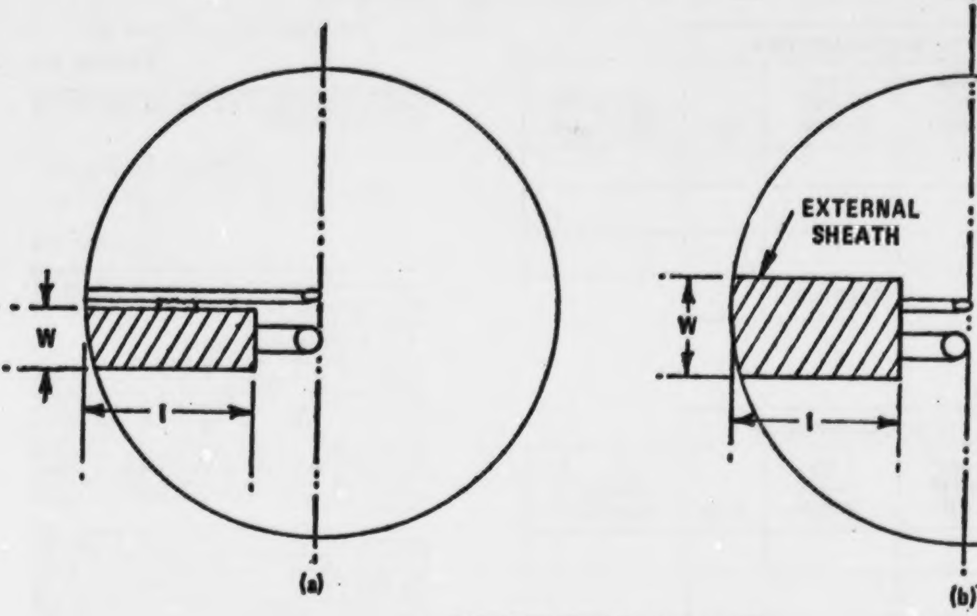
4.1.5.1.1 When an isolated Type S pitot tube is calibrated, select a calibration point at or near the center of the duct, and follow the procedures outlined in Sections 4.1.3 and 4.1.4 above. The Type S pitot coefficients so obtained, i.e., $\bar{C}_p$ (side A) and $\bar{C}_p$ (side B), will be valid, so long as either: (1) the isolated pitot tube is used; or (2) the pitot tube is used with other components (nozzle, thermocouple, sample probe) in an arrangement that is free from aerodynamic interference effects (see Figures 2-6 through 2-8).

4.1.5.1.2 For Type S pitot tube-thermocouple combinations (without sample probe), select a calibration point at or near the center of the duct, and follow the procedures outlined in Sections 4.1.3 and 4.1.4 above. The coefficients so obtained will be valid so long as the pitot tube-thermocouple combination is used by itself or with other components in an interference-free arrangement (Figures 2-6 and 2-8).

4.1.5.1.3 For assemblies with sample probes, the calibration point should be located at or near the center of the duct; however, insertion of a probe sheath into a small duct may cause significant cross-sectional area blockage and yield incorrect coefficient values (Citation 9 in Section 6). Therefore, to minimize the blockage effect, the calibration point may be a few inches off-center if necessary. The actual blockage effect will be negligible when the theoretical blockage, as determined by a projected-area model of the probe sheath, is 2 percent or less of the duct cross-sectional area for assemblies without external sheaths (Figure 2-10a), and 3 percent or less for assemblies with external sheaths (Figure 2-10b).

4.1.5.2 For those probe assemblies in which pitot tube-nozzle interference is a factor (i.e., those in which the pitot-nozzle separation distance fails to meet the specification illustrated in Figure 2-6a), the value of $C_{p(s)}$ depends upon the amount of free-space between the tube and nozzle, and therefore is a function of nozzle size. In these instances, separate calibrations shall be performed with each of the commonly used nozzle sizes in place. Note that the single-velocity calibration technique is acceptable for this purpose, even though the larger nozzle sizes (>0.635 cm or ¼ in.) are not ordinarily used for isokinetic sampling at velocities around 915 m/min (3,000 ft/min), which is the calibration velocity; note also that it is not necessary to draw an isokinetic sample during calibration (see Citation 19 in Section 6).87

4.1.5.3 For a probe assembly constructed such that its pitot tube is always used in the same orientation, only one side of the pitot tube need be calibrated (the side which will face the flow). The pitot tube must still meet the alignment specifications of Figure 2-2 or 2-3, however, and must have an average deviation (σ) value of 0.01 or less (see Section 4.1.4.4).



$$\text{ESTIMATED SHEATH BLOCKAGE (\%)} = \left[\frac{l \times W}{\text{DUCT AREA}}\right] \times 100$$

Figure 2-10. Projected-area models for typical pitot tube assemblies.

4.1.6 Field Use and Recalibration.

4.1.6.1 Field Use.

4.1.6.1.1 When a Type S pitot tube (isolated tube or assembly) is used in the field, the appropriate coefficient value (whether assigned or obtained by calibration) shall be used to perform velocity calculations. For calibrated Type S pitot tubes, the A side coefficient shall be used when the A side of the tube faces the flow, and the B side coefficient shall be used when the B side faces the flow; alternatively, the arithmetic average of the A and B side coefficient values may be used, irrespective of which side faces the flow.

4.1.6.1.2 When a probe assembly is used to sample a small duct (12 to 36 in. in diameter), the probe sheath sometimes blocks a significant part of the duct cross-section, causing a reduction in the effective value of $\overline{C}_{p(s)}$. Consult Citation 9 in Section 6 for details. Conventional pitot-sampling probe assemblies are not recommended for use in ducts having inside diameters smaller than 12 inches (Citation 16 in Section 6).

4.1.6.2 Recalibration.

4.1.6.2.1 Isolated Pitot Tubes. After each field use, the pitot tube shall be carefully reexamined in top, side, and end views. If the pitot face openings are still aligned within the specifications illustrated in Figure 2-2 or 2-3, it can be assumed that the baseline coefficient of the pitot tube has not changed. If, however, the tube has been damaged to the extent that it no longer meets the specifications of Figure 2-2 or 2-3, the damage shall either be repaired to restore proper alignment of the face openings or the tube shall be discarded.

4.1.6.2.2 Pitot Tube Assemblies. After each field use, check the face opening alignment of the pitot tube, as in Section 4.1.6.2.1; also, remeasure the intercomponent spacings of the assembly. If the intercomponent spacings have not changed and the face opening alignment is acceptable, it can be assumed that the coefficient of the assembly has not changed. If the face opening alignment is no longer within the specifications of Figures 2-2 or 2-3, either repair the damage or replace the pitot tube (calibrating the new assembly, if necessary). If the intercomponent spacings have changed, restore the original spacings or recalibrate the assembly.

4.2 Standard pitot tube (if applicable). If a standard pitot tube is used for the velocity traverse, the tube shall be constructed according to the criteria of Section 2.7 and shall be assigned a baseline coefficient value of 0.99. If the standard pitot tube is used as part of an assembly, the tube shall be in an interference-free arrangement (subject to the approval of the Administrator).

4.3 Temperature Gauges. After each field use, calibrate dial thermometers, liquid-filled bulb thermometers, thermocouple-potentiometer systems, and other gauges at a temperature within 10 percent of the average absolute stack temperature. For temperatures up to 405° C (761° F), use an ASTM mercury-in-glass reference thermometer, or equivalent, as a reference; alternatively, either a reference thermocouple and potentiometer (calibrated by NBS) or thermometric fixed points, e.g., ice bath and boiling water (corrected for barometric pressure) may be used. For temperatures above 405° C (761° F), use an NBS-calibrated reference thermocouple-potentiometer system or an alternate reference, subject to the approval of the Administrator.

If, during calibration, the absolute temperatures measured with the gauge being calibrated and the reference gauge agree within 1.5 percent, the temperature data taken in the field shall be considered valid. Otherwise, the pollutant emission test shall either be considered invalid or adjustments (if appropriate) of the test results shall be made, subject to the approval of the Administrator.

4.4 Barometer. Calibrate the barometer used against a mercury barometer.

5. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

5.1 Nomenclature.

A = Cross-sectional area of stack, m² (ft²).

B_{ws} = Water vapor in the gas stream (from Method 5 or Reference Method 4), proportion by volume.

C_p = Pitot tube coefficient, dimensionless.

K_p = Pitot tube constant,

$$34.97\ \frac{\text{m}}{\text{sec}}\left[\frac{(g/g\text{-mole})(\text{mm Hg})}{(^\circ\text{K})(\text{mm H}_2\text{O})}\right]^{1/2}$$

for the metric system and

$$85.49\ \frac{\text{ft}}{\text{sec}}\left[\frac{(\text{lb/lb-mole})(\text{in. Hg})}{(^\circ\text{R})(\text{in. H}_2\text{O})}\right]^{1/2}$$

for the English system.

M_d = Molecular weight of stack gas, dry basis (see Section 3.6) g/g-mole (lb/lb-mole).

M_s = Molecular weight of stack gas, wet basis, g/g-mole (lb/lb-mole).

$= M_d\,(1-B_{ws})+18.0\,B_{ws}$ Equation 2-5

P_{bar} = Barometric pressure at measurement site, mm Hg (in. Hg).

P_g = Stack static pressure, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

$= P_{bar}+P_g$ Equation 2-6

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

Q_{sd} = Dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr).

t_s = Stack temperature, °C (°F).

T_s = Absolute stack temperature, °K (°R).

$= 273 + t_s$ for metric Equation 2-7

$= 460 + t_s$ for English Equation 2-8

T_{std} = Standard absolute temperature, 293 °K (528° R)

v_s = Average stack gas velocity, m/sec (ft/sec).

Δp = Velocity head of stack gas, mm H₂O (in. H₂O).

3,600 = Conversion factor, sec/hr.

18.0 = Molecular weight of water, g/g-mole (lb-lb-mole).

5.2 Average stack gas velocity.

$$v_s = K_p C_p (\sqrt{\Delta p})_{avg} \sqrt{\frac{T_{s(avg)}}{P_s M_s}}$$

Equation 2-9

5.3 Average stack gas dry volumetric flow rate.

$$Q_{sd} = 3{,}600(1-B_{ws})v_s A\left(\frac{T_{std}}{T_{s(avg)}}\right)\left(\frac{P_s}{P_{std}}\right)$$

Equation 2-10

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Method 3—Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted from a stack, by one of the following methods: (1) single-point, grab sampling; (2) single-point, integrated sampling; or (3) multi-point, integrated sampling. The gas sample is analyzed for percent carbon dioxide (CO_2), percent oxygen (O_2), and, if necessary, percent carbon monoxide (CO). If a dry molecular weight determination is to be made, either an Orsat or a Fyrite[1] analyzer may be used for the analysis; for excess air or emission rate correction factor determination, an Orsat analyzer must be used.

1.2 Applicability. This method is applicable for determining CO_2 and O_2 concentrations, excess air, and dry molecular weight of a sample from a gas stream of a fossil-fuel combustion process. The method may also be applicable to other processes where it has been determined that compounds other than CO_2, O_2, CO, and nitrogen (N_2) are not present in concentrations sufficient to affect the results.

Other methods, as well as modifications to the procedure described herein, are also applicable for some or all of the above determinations. Examples of specific methods and modifications include: (1) a multi-point sampling method using an Orsat analyzer to analyze individual grab samples obtained at each point; (2) a method using CO_2 or O_2 and stoichiometric calculations to determine dry molecular weight and excess air; (3) assigning a value of 30.0 for dry molecular weight, in lieu of actual measurements, for processes burning natural gas, coal, or oil. These methods and modifications may be used, but are subject to the approval of the Administrator. U.S. Environmental Protection Agency 87

2. *Apparatus*

As an alternative to the sampling apparatus and systems described herein, other sampling systems (e.g., liquid displacement) may be used provided such systems are capable of obtaining a representative sample and maintaining a constant sampling rate, and are otherwise capable of yielding acceptable results. Use of such systems is subject to the approval of the Administrator.

2.1 Grab Sampling (Figure 3-1).

2.1.1 Probe. The probe should be made of stainless steel or borosilicate glass tubing and should be equipped with an in-stack or out-stack filter to remove particulate matter (a plug of glass wool is satisfactory for this purpose). Any other material inert to O_2, CO_2, CO, and N_2 and resistant to temperature at sampling conditions may be used for the probe; examples of such material are aluminum, copper, quartz glass and Teflon.

2.1.2 Pump. A one-way squeeze bulb, or equivalent, is used to transport the gas sample to the analyzer.

2.2 Integrated Sampling (Figure 3-2).

2.2.1 Probe. A probe such as that described in Section 2.1.1 is suitable.

2.2.2 Condenser. An air-cooled or water-cooled condenser, or other condenser that will not remove O_2, CO_2, CO, and N_2, may be used to remove excess moisture which would interfere with the operation of the pump and flow meter.

2.2.3 Valve. A needle valve is used to adjust sample gas flow rate.

2.2.4 Pump. A leak-free, diaphragm-type pump, or equivalent, is used to transport sample gas to the flexible bag. Install a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter.

2.2.5 Rate Meter. The rotameter, or equivalent rate meter, used should be capable of measuring flow rate to within ±2 percent of the selected flow rate. A flow rate range of 500 to 1000 cm^3/min is suggested.

2.2.6 Flexible Bag. Any leak-free plastic (e.g., Tedlar, Mylar, Teflon) or plastic-coated aluminum (e.g., aluminized Mylar) bag, or equivalent, having a capacity consistent with the selected flow rate and time length of the test run, may be used. A capacity in the range of 55 to 90 liters is suggested.

To leak-check the bag, connect it to a water manometer and pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O). Allow to stand for 10 minutes. Any displacement in the water manometer indicates a leak. An alternative leak-check method is to pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O) and allow to stand overnight. A deflated bag indicates a leak.

2.2.7 Pressure Gauge. A water-filled U-tube manometer, or equivalent, of about 28 cm (12 in.) is used for the flexible bag leak-check.

2.2.8 Vacuum Gauge. A mercury manometer, or equivalent, of at least 760 mm Hg (30 in. Hg) is used for the sampling train leak-check.

2.3 Analysis. For Orsat and Fyrite analyzer maintenance and operation procedures, follow the instructions recommended by the manufacturer, unless otherwise specified herein.

2.3.1 Dry Molecular Weight Determination. An Orsat analyzer or Fyrite type combustion gas analyzer may be used.

2.3.2 Emission Rate Correction Factor or Excess Air Determination. An Orsat analyzer must be used. For low CO_2 (less than 4.0 percent) or high O_2 (greater than 15.0 percent) concentrations, the measuring burette of the Orsat must have at least 0.1 percent subdivisions.

3. *Dry Molecular Weight Determination*

Any of the three sampling and analytical procedures described below may be used for determining the dry molecular weight.

3.1 Single-Point, Grab Sampling and Analytical Procedure.

3.1.1 The sampling point in the duct shall either be at the centroid of the cross section or at a point no closer to the walls than 1.00 m (3.3 ft), unless otherwise specified by the Administrator.

3.1.2 Set up the equipment as shown in Figure 3-1, making sure all connections ahead of the analyzer are tight and leak-free. If an Orsat analyzer is used, it is recommended that the analyzer be leaked-checked by following the procedure in Section 5; however, the leak-check is optional.

3.1.3 Place the probe in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Draw a sample into the analyzer and immediately analyze it for percent CO_2 and percent O_2. Determine the percentage of the gas that is N_2 and CO by subtracting the sum of the percent CO_2 and percent O_2 from 100 percent. Calculate the dry molecular weight as indicated in Section 6.2.

3.1.4 Repeat the sampling, analysis, and calculation procedures, until the dry molecular weights of any three grab samples differ from their mean by no more than 0.3 g/g-mole (0.3 lb/lb-mole). Average these three molecular weights, and report the results to the nearest 0.1 g/g-mole (lb/lb-mole).

3.2 Single-Point, Integrated Sampling and Analytical Procedure.

3.2.1 The sampling point in the duct shall be located as specified in Section 3.1.1.

3.2.2 Leak-check (optional) the flexible bag as in Section 2.2.6. Set up the equipment as shown in Figure 3-2. Just prior to sampling, leak-check (optional) the train by placing a vacuum gauge at the condenser inlet, pulling a vacuum of at least 250 mm Hg (10 in. Hg), plugging the outlet at the quick disconnect, and then turning off the pump. The vacuum should remain stable for at least 0.5 minute. Evacuate the flexible bag. Connect the probe and place it in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Next, connect the bag and make sure that all connections are tight and leak free.

3.2.3 Sample at a constant rate. The sampling run should be simultaneous with, and for the same total length of time as, the pollutant emission rate determination. Collection of at least 30 liters (1.00 ft^3) of sample gas is recommended; however, smaller volumes may be collected, if desired.

3.2.4 Obtain one integrated flue gas sample during each pollutant emission rate determination. Within 8 hours after the sample is taken, analyze it for percent CO_2 and percent O_2 using either an Orsat analyzer or a Fyrite-type combustion gas analyzer. If an Orsat analyzer is used, it is recommended that the Orsat leak-check described in Section 5 be performed before this determination; however, the check is optional. Determine the percentage of the gas that is N_2 and CO by subtracting the sum of the percent CO_2 and percent O_2 from 100 percent. Calculate the dry molecular weight as indicated in Section 6.2. 87

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[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

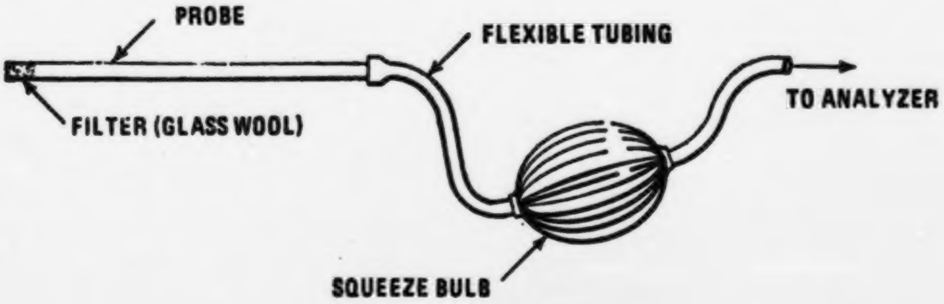

Figure 3-1. Grab-sampling train.

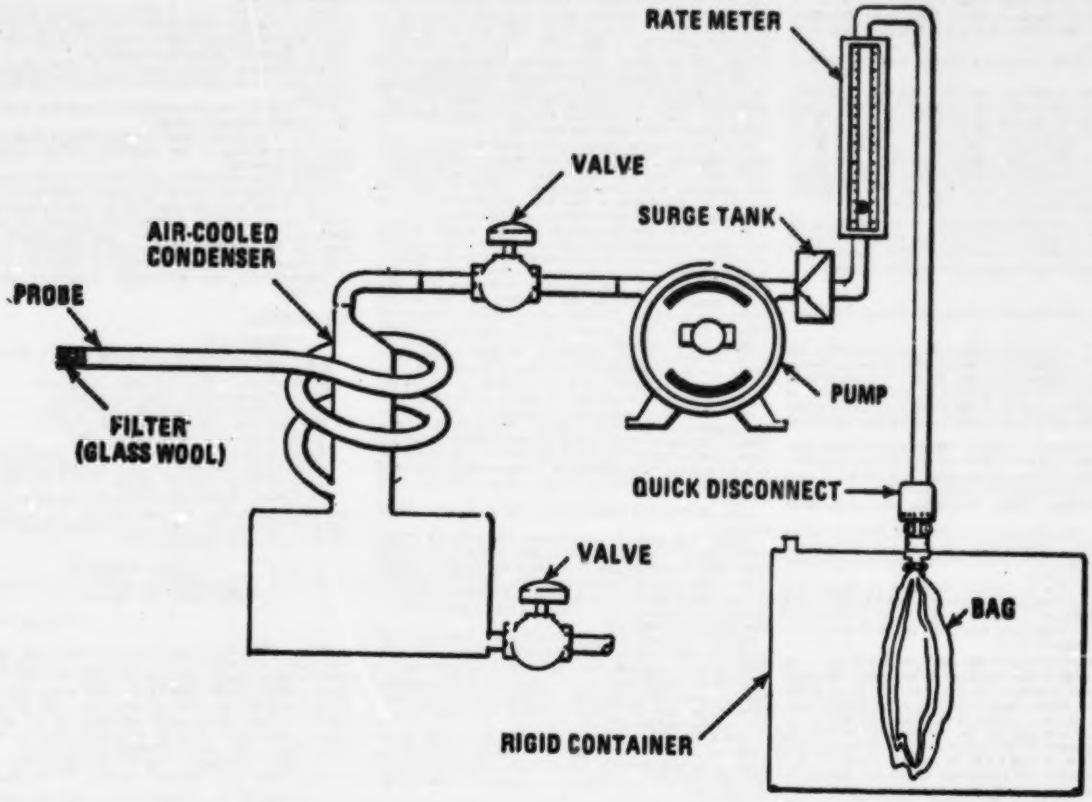
RATE METER
VALVE
SURGE TANK
AIR-COOLED CONDENSER
PROBE
PUMP
FILTER (GLASS WOOL)
QUICK DISCONNECT
VALVE
BAG
RIGID CONTAINER

Figure 3-2. Integrated gas-sampling train.

TIME	TRAVERSE PT.	Q lpm	% DEV.[a]
	AVERAGE		

^{a}% DEV = $\left(\frac{Q - Q_{avg}}{Q_{avg}}\right)100$ (MUST BE $<$10%)

Figure 3-3. Sampling rate data.

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3.2.5 Repeat the analysis and calculation procedures until the individual dry molecular weights for any three analyses differ from their mean by no more than 0.3 g/g-mole (0.3 lb/lb-mole). Average these three molecular weights, and report the results to the nearest 0.1 g/g-mole (0.1 lb/lb-mole).

3.3 Multi-Point, Integrated Sampling and Analytical Procedure.

3.3.1 Unless otherwise specified by the Administrator, a minimum of eight traverse points shall be used for circular stacks having diameters less then 0.61 m (24 in.), a minimum of nine shall be used for rectangular stacks having equivalent diameters less than 0.61 m (24 in.), and a minimum of twelve traverse points shall be used for all other cases. The traverse points shall be located according to Method 1. The use of fewer points is subject to approval of the Administrator.

3.3.2 Follow the procedures outlined in Sections 3.2.2 through 3.2.5, except for the following: traverse all sampling points and sample at each point for an equal length of time. Record sampling data as shown in Figure 3-3.

4. *Emission Rate Correction Factor or Excess Air Determination*

NOTE.—A Fyrite-type combustion gas analyzer is not acceptable for excess air or emission rate correction factor determination, unless approved by the Administrator. If both percent CO_2 and percent O_2 are measured, the analytical results of any of the three procedures given below may also be used for calculating the dry molecular weight.

Each of the three procedures below shall be used only when specified in an applicable subpart of the standards. The use of these procedures for other purposes must have specific prior approval of the Administrator.

4.1 Single-Point, Grab Sampling and Analytical Procedure.

4.1.1 The sampling point in the duct shall either be at the centroid of the cross-section or at a point no closer to the walls than 1.00 m (3.3 ft), unless otherwise specified by the Administrator.

4.1.2 Set up the equipment as shown in Figure 3-1, making sure all connections ahead of the analyzer are tight and leak-free. Leak-check the Orsat analyzer according to the procedure described in Section 5. This leak-check is mandatory.

4.1.3 Place the probe in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Draw a sample into the analyzer. For emission rate correction factor determination, immediately analyze the sample, as outlined in Sections 4.1.4 and 4.1.5, for percent CO_2 or percent O_2. If excess air is desired, proceed as follows: (1) immediately analyze the sample, as in Sections 4.1.4 and 4.1.5, for percent CO_2, O_2, and CO; (2) determine the percentage of the gas that is N_2 by subtracting the sum of the percent CO_2, percent O_2, and percent CO from 100 percent; and (3) calculate percent excess air as outlined in Section 6.2.

4.1.4 To ensure complete absorption of the CO_2, O_2, or if applicable, CO, make repeated passes through each absorbing solution until two consecutive readings are the same. Several passes (three or four) should be made between readings. (If constant readings cannot be obtained after three consecutive readings, replace the absorbing solution.)

4.1.5 After the analysis is completed, leak-check (mandatory) the Orsat analyzer once again, as described in Section 5. For the results of the analysis to be valid, the Orsat analyzer must pass this leak test before and after the analysis. NOTE.—Since this single-point, grab sampling and analytical procedure is normally conducted in conjunction with a single-point, grab sampling and analytical procedure for a pollutant, only one analysis is ordinarily conducted. Therefore, great care must be taken to obtain a valid sample and analysis. Although in most cases only CO_2 or O_2 is required, it is recommended that both CO_2 and O_2 be measured, and that Citation 5 in the Bibliography be used to validate the analytical data.

4.2 Single-Point, Integrated Sampling and Analytical Procedure.

4.2.1 The sampling point in the duct shall be located as specified in Section 4.1.1.

4.2.2 Leak-check (mandatory) the flexible bag as in Section 2.2.6. Set up the equipment as shown in Figure 3-2. Just prior to sampling, leak-check (mandatory) the train by placing a vacuum gauge at the condenser inlet, pulling a vacuum of at least 250 mm Hg (10 in. Hg), plugging the outlet at the quick disconnect, and then turning off the pump. The vacuum shall remain stable for at least 0.5 minute. Evacuate the flexible bag. Connect the probe and place it in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Next, connect the bag and make sure that all connections are tight and leak free.

4.2.3 Sample at a constant rate, or as specified by the Administrator. The sampling run must be simultaneous with, and for the same total length of time as, the pollutant emission rate determination. Collect at least 30 liters (1.00 ft³) of sample gas. Smaller volumes may be collected, subject to approval of the Administrator.

4.2.4 Obtain one integrated flue gas sample during each pollutant emission rate determination. For emission rate correction factor determination, analyze the sample within 4 hours after it is taken for percent CO_2 or percent O_2 (as outlined in Sections 4.2.5 through 4.2.7). The Orsat analyzer must be leak-checked (see Section 5) before the analysis. If excess air is desired, proceed as follows: (1) within 4 hours after the sample is taken, analyze it (as in Sections 4.2.5 through 4.2.7) for percent CO_2, O_2, and CO; (2) determine the percentage of the gas that is N_2 by subtracting the sum of the percent CO_2, percent O_2, and percent CO from 100 percent; (3) calculate percent excess air, as outlined in Section 6.2.

4.2.5 To ensure complete absorption of the CO_2, O_2, or if applicable, CO, make repeated passes through each absorbing solution until two consecutive readings are the same. Several passes (three or four) should be made between readings. (If constant readings cannot be obtained after three consecutive readings, replace the absorbing solution.)

4.2.6 Repeat the analysis until the following criteria are met:

4.2.6.1 For percent CO_2, repeat the analytical procedure until the results of any three analyses differ by no more than (a) 0.3 percent by volume when CO_2 is greater than 4.0 percent or (b) 0.2 percent by volume when CO_2 is less than or equal to 4.0 percent. Average the three acceptable values of percent CO_2 and report the results to the nearest 0.1 percent.

4.2.6.2 For percent O_2, repeat the analytical procedure until the results of any three analyses differ by no more than (a) 0.3 percent by volume when O_2 is less than 15.0 percent or (b) 0.2 percent by volume when O_2 is greater than or equal to 15.0 percent. Average the three acceptable values of percent O_2 and report the results to the nearest 0.1 percent. 87

4.2.6.3 For percent CO, repeat the analytical procedure until the results of any three analyses differ by no more than 0.3 percent. Average the three acceptable values of percent CO and report the results to the nearest 0.1 percent.

4.2.7 After the analysis is completed, leak-check (mandatory) the Orsat analyzer once again, as described in Section 5. For the results of the analysis to be valid, the Orsat analyzer must pass this leak test before and after the analysis. Note: Although in most instances only CO_2 or O_2 is required, it is recommended that both CO_2 and O_2 be measured, and that Citation 5 in the Bibliography be used to validate the analytical data.

4.3 Multi-Point, Integrated Sampling and Analytical Procedure.

4.3.1 Both the minimum number of sampling points and the sampling point location shall be as specified in Section 3.3.1 of this method. The use of fewer points than specified is subject to the approval of the Administrator.

4.3.2 Follow the procedures outlined in Sections 4.2.2 through 4.2.7, except for the following: Traverse all sampling points and sample at each point for an equal length of time. Record sampling data as shown in Figure 3-3.

5. *Leak-Check Procedure for Orsat Analyzers*

Moving an Orsat analyzer frequently causes it to leak. Therefore, an Orsat analyzer should be thoroughly leak-checked on site before the flue gas sample is introduced into it. The procedure for leak-checking an Orsat analyzer is:

5.1.1 Bring the liquid level in each pipette up to the reference mark on the capillary tubing and then close the pipette stopcock.

5.1.2 Raise the leveling bulb sufficiently to bring the confining liquid meniscus onto the graduated portion of the burette and then close the manifold stopcock.

5.1.3 Record the meniscus position.

5.1.4 Observe the meniscus in the burette and the liquid level in the pipette for movement over the next 4 minutes.

5.1.5 For the Orsat analyzer to pass the leak-check, two conditions must be met.

5.1.5.1 The liquid level in each pipette must not fall below the bottom of the capillary tubing during this 4-minute interval.

5.1.5.2 The meniscus in the burette must not change by more than 0.2 ml during this 4-minute interval.

5.1.6 If the analyzer fails the leak-check procedure, all rubber connections and stopcocks should be checked until the cause of the leak is identified. Leaking stopcocks must be disassembled, cleaned, and regreased. Leaking rubber connections must be replaced. After the analyzer is reassembled, the leak-check procedure must be repeated.

6. *Calculations*

6.1 Nomenclature.

M_d = Dry molecular weight, g/g-mole (lb/lb-mole).
%EA = Percent excess air.
$\%CO_2$ = Percent CO_2 by volume (dry basis).
$\%O_2$ = Percent O_2 by volume (dry basis).
%CO = Percent CO by volume (dry basis).
$\%N_2$ = Percent N_2 by volume (dry basis).
0.264 = Ratio of O_2 to N_2 in air, v/v.
0.280 = Molecular weight of N_2 or CO, divided by 100.
0.320 = Molecular weight of O_2 divided by 100.
0.440 = Molecular weight of CO_2 divided by 100.

6.2 Percent Excess Air. Calculate the percent excess air (if applicable), by substituting the appropriate values of percent O_2, CO, and N_2 (obtained from Section 4.1.3 or 4.2.4) into Equation 3-1.

$$\%EA=\left[\frac{\%O_2-0.5\%CO}{0.264\,\%N_2-(\%O_2-0.5\,\%CO)}\right]100$$

Equation 3-1 87

NOTE.—The equation above assumes that ambient air is used as the source of O_2 and that the fuel does not contain appreciable amounts of N_2 (as do coke oven or blast furnace gases). For those cases when appreciable amounts of N_2 are present (coal, oil, and natural gas do not contain appreciable amounts of N_2) or when oxygen enrichment is used, alternate methods, subject to approval of the Administrator, are required.

6.3 Dry Molecular Weight. Use Equation 3-2 to calculate the dry molecular weight of the stack gas

$$M_d=0.440(\%CO_2)+0.320(\%O_2)+0.280(\%N_2+\%CO)$$

Equation 3-2

NOTE.—The above equation does not consider argon in air (about 0.9 percent, molecular weight of 37.7). A negative error of about 0.4 percent is introduced. The tester may opt to include argon in the analysis using procedures subject to approval of the Administrator.

7. *Bibliography*

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METHOD 4—DETERMINATION OF MOISTURE CONTENT IN STACK GASES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted at a constant rate from the source; moisture is removed from the sample stream and determined either volumetrically or gravimetrically.

1.2 Applicability. This method is applicable for determining the moisture content of stack gas.

Two procedures are given. The first is a reference method, for accurate determinations of moisture content (such as are needed to calculate emission data). The second is an approximation method, which provides estimates of percent moisture to aid in setting isokinetic sampling rates prior to a pollutant emission measurement run. The approximation method described herein is only a suggested approach; alternative means for approximating the moisture content, e.g., drying tubes, wet bulb-dry bulb techniques, condensation techniques, stoichiometric calculations, previous experience, etc., are also acceptable.

The reference method is often conducted simultaneously with a pollutant emission measurement run; when it is, calculation of percent isokinetic, pollutant emission rate, etc., for the run shall be based upon the results of the reference method or its equivalent; these calculations shall not be based upon the results of the approximation method, unless the approximation method is shown, to the satisfaction of the Administrator, U.S. Environmental Protection Agency, to be capable of yielding results within 1 percent H_2O of the reference method.

NOTE.—The reference method may yield questionable results when applied to saturated gas streams or to streams that contain water droplets. Therefore, when these conditions exist or are suspected, a second determination of the moisture content shall be made simultaneously with the reference method, as follows: Assume that the gas stream is saturated. Attach a temperature sensor [capable of measuring to ±1° C (2° F)] to the reference method probe. Measure the stack gas temperature at each traverse point (see Section 2.2.1) during the reference method traverse; calculate the average stack gas temperature. Next, determine the moisture percentage, either by: (1) using a psychrometric chart and making appropriate corrections if stack pressure is different from that of the chart, or (2) using saturation vapor pressure tables. In cases where the psychrometric chart or the saturation vapor pressure tables are not applicable (based on evaluation of the process), alternate methods, subject to the approval of the Administrator, shall be used.

2. *Reference Method*

The procedure described in Method 5 for determining moisture content is acceptable as a reference method.

2.1 Apparatus. A schematic of the sampling train used in this reference method is shown in Figure 4-1. All components shall be maintained and calibrated according to the procedure outlined in Method 5.

2.1.1 Probe. The probe is constructed of stainless steel or glass tubing, sufficiently heated to prevent water condensation, and is equipped with a filter, either in-stack (e.g., a plug of glass wool inserted into the end of the probe) or heated out-stack (e.g., as described in Method 5), to remove particulate matter.

When stack conditions permit, other metals or plastic tubing may be used fo. the probe, subject to the approval of the Administrator.

2.1.2 Condenser. The condenser consists of four impingers connected in series with ground glass, leak-free fittings or any similarly leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with a 1.3 centimeter (½ inch) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator.

The first two impingers shall contain known volumes of water, the third shall be empty, and the fourth shall contain a known weight of 6- to 16-mesh indicating type silica gel, or equivalent desiccant. If the silica gel has been previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. A thermometer, capable of measuring temperature to within 1° C (2° F), shall be placed at the outlet of the fourth impinger, for monitoring purposes.

Alternatively, any system may be used (subject to the approval of the Administrator) that cools the sample gas stream and allows measurement of both the water that has been condensed and the moisture leaving the condenser, each to within 1 ml or 1 g. Acceptable means are to measure the condensed water, either gravimetrically or volumetrically, and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures, or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap, with exit gases kept below 20° C (68° F), and determining the weight gain.

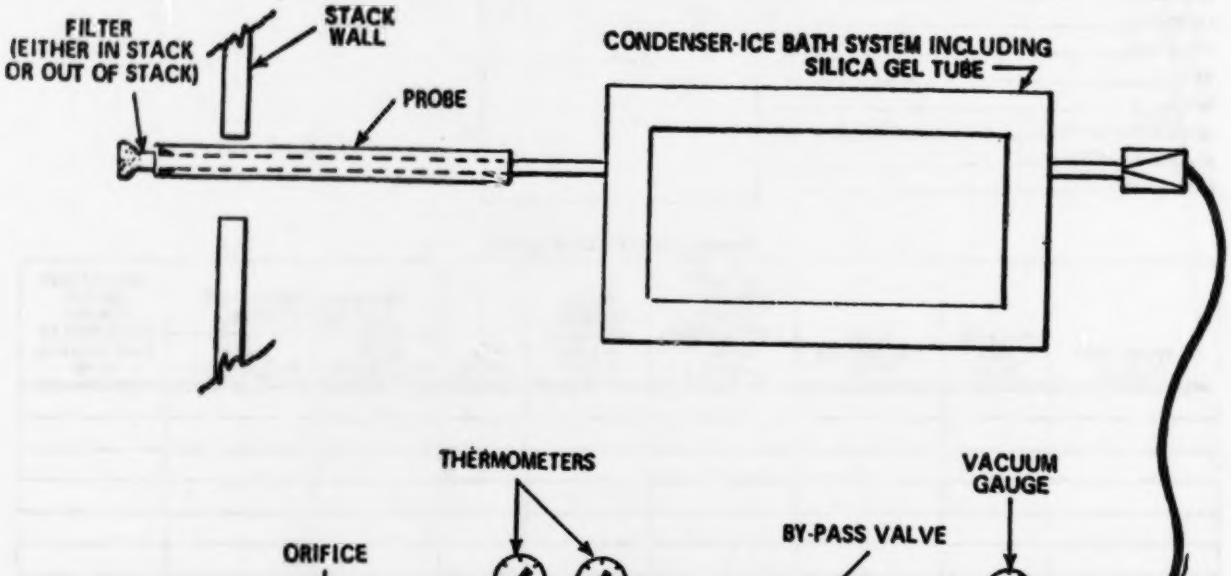

Figure 4-1. Moisture sampling train-reference method.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump, to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.3 Cooling System. An ice bath container and crushed ice (or equivalent) are used to aid in condensing moisture.

2.1.4 Metering System. This system includes a vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment as shown in Figure 4-1. Other metering systems, capable of maintaining a constant sampling rate and determining sample gas volume, may be used, subject to the approval of the Administrator.

2.1.5 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg) may be used. In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.6 Graduated Cylinder and/or Balance. These items are used to measure condensed water and moisture caught in the silica gel to within 1 ml or 0.5 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. These balances are suitable for use here.

2.2 Procedure. The following procedure is written for a condenser system (such as the impinger system described in Section 2.1.2) incorporating volumetric analysis to measure the condensed moisture, and silica gel and gravimetric analysis to measure the moisture leaving the condenser.

2.2.1 Unless otherwise specified by the Administrator, a minimum of eight traverse points shall be used for circular stacks having diameters less than 0.61 m (24 in.), a minimum of nine points shall be used for rectangular stacks having equivalent diameters less than 0.61 m (24 in.), and a minimum of twelve traverse points shall be used in all other cases. The traverse points shall be located according to Method 1. The use of fewer points is subject to the approval of the Administrator. Select a suitable probe and probe length such that all traverse points can be sampled. Consider sampling from opposite sides of the stack (four total sampling ports) for large stacks, to permit use of shorter probe lengths. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point. Place known volumes of water in the first two impingers. Weigh and record the weight of the silica gel to the nearest 0.5 g, and transfer the silica gel to the fourth impinger; alternatively, the silica gel may first be transferred to the impinger, and the weight of the silica gel plus impinger recorded.[87]

2.2.2 Select a total sampling time such that a minimum total gas volume of 0.60 scm (21 scf) will be collected, at a rate no greater than 0.021 m³/min (0.75 cfm). When both moisture content and pollutant emission rate are to be determined, the moisture determination shall be simultaneous with, and for the same total length of time as, the pollutant emission rate run, unless otherwise specified in an applicable subpart of the standards.

2.2.3 Set up the sampling train as shown in Figure 4-1. Turn on the probe heater and (if applicable) the filter heating system to temperatures of about 120° C (248° F), to prevent water condensation ahead of the condenser; allow time for the temperatures to stabilize. Place crushed ice in the ice bath container. It is recommended, but not required, that a leak check be done, as follows: Disconnect the probe from the first impinger or (if applicable) from the filter holder. Plug the inlet to the first impinger (or filter holder) and pull a 380 mm (15 in.) Hg vacuum; a lower vacuum may be used, provided that it is not exceeded during the test. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m³/min (0.02 cfm), whichever is less, is unacceptable. Following the leak check, reconnect the probe to the sampling train.[87]

2.2.4 During the sampling run, maintain a sampling rate within 10 percent of constant rate, or as specified by the Administrator. For each run, record the data required on the example data sheet shown in Figure 4-2. Be sure to record the dry gas meter reading at the beginning and end of each sampling time increment and whenever sampling is halted. Take other appropriate readings at each sample point, at least once during each time increment.

2.2.5 To begin sampling, position the probe tip at the first traverse point. Immediately start the pump and adjust the flow to the desired rate. Traverse the cross section, sampling at each traverse point for an equal length of time. Add more ice and, if necessary, salt to maintain a temperature of less than 20° C (68° F) at the silica gel outlet.

2.2.6 After collecting the sample, disconnect the probe from the filter holder (or from the first impinger) and conduct a leak check (mandatory) as described in Section 2.2.3. Record the leak rate. If the leakage rate exceeds the allowable rate, the tester shall either reject the test results or shall correct the sample volume as in Section 6.3 of Method 5. Next, measure the volume of the moisture condensed to the nearest ml. Determine the increase in weight of the silica gel (or silica gel plus impinger) to the nearest 0.5 g. Record this information (see example data sheet, Figure 4-3) and calculate the moisture percentage, as described in 2.3 below.

PLANT____________________
LOCATION____________________
OPERATOR____________________
DATE____________________
RUN NO.____________________
AMBIENT TEMPERATURE____________________
BAROMETRIC PRESSURE____________________
PROBE LENGTH m(ft)____________________

SCHEMATIC OF STACK CROSS SECTION

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	STACK TEMPERATURE °C (°F)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER (ΔH), mm(in.) H_2O	METER READING GAS SAMPLE VOLUME m^3 (ft^3)	ΔV_m m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
						INLET ($T_{m_{in}}$), °C (°F)	OUTLET ($T_{m_{out}}$), °C (°F)	
TOTAL						Avg.	Avg.	
AVERAGE						Avg.		

Figure 4-2. Field moisture determination-reference method.[87]

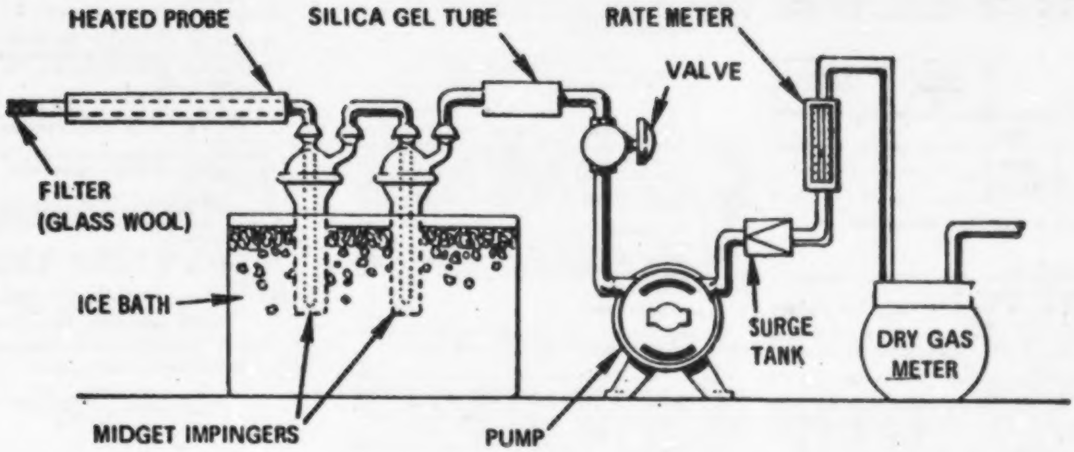
HEATED PROBE
SILICA GEL TUBE
RATE METER
VALVE
FILTER (GLASS WOOL)
ICE BATH
SURGE TANK
DRY GAS METER
MIDGET IMPINGERS
PUMP

Figure 4-4. Moisture-sampling train - approximation method.

LOCATION ____________________ COMMENTS
TEST ____________________
DATE ____________________
OPERATOR ____________________

BAROMETRIC PRESSURE ____________________

CLOCK TIME	GAS VOLUME THROUGH METER, (Vm), m^3 (ft^3)	RATE METER SETTING m^3/min. (ft^3/min.)	METER TEMPERATURE, °C (°F)

Figure 4-5. Field moisture determination - approximation method.

2.3 Calculations. Carry out the following calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g
FINAL		
INITIAL		
DIFFERENCE		

Figure 4-3. Analytical data - reference method.

2.3.1 Nomenclature.

B_{ws} = Proportion of water vapor, by volume, in the gas stream.
M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).
P_m = Absolute pressure (for this method, same as barometric pressure) at the dry gas meter, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R = Ideal gas constant, 0.06236 (mm Hg) (m^3)/(g-mole) (°K) for metric units and 21.85 (in. Hg) (ft^3)/(lb-mole) (°R) for English units.
T_m = Absolute temperature at meter, °K (°R).
T_{std} = Standard absolute temperature, 293° K (528° R).
V_m = Dry gas volume measured by dry gas meter, dcm (dcf).
ΔV_m = Incremental dry gas volume measured by dry gas meter at each traverse point, dcm (dcf).
$V_{m(std)}$ = Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
$V_{wc(std)}$ = Volume of water vapor condensed corrected to standard conditions, scm (scf).
$V_{wsg(std)}$ = Volume of water vapor collected in silica gel corrected to standard conditions, scm (scf).
V_f = Final volume of condenser water, ml.
V_i = Initial volume, if any, of condenser water, ml.
W_f = Final weight of silica gel or silica gel plus impinger, g.
W_i = Initial weight of silica gel or silica gel plus impinger, g.
Y = Dry gas meter calibration factor.
ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).[87]

2.3.2 Volume of water vapor condensed.

$$V_{wc(std)} = \frac{(V_f - V_i)\rho_w R T_{std}}{P_{std} M_w} = K_1 (V_f - V_i)$$

Equation 4-1

where:
K_1 = 0.001333 m^3/ml for metric units
= 0.04707 ft^3/ml for English units

2.3.3 Volume of water vapor collected in silica gel.

$$V_{wsg(std)} = \frac{(W_f - W_i) R T_{std}}{P_{std} M_w} = K_2 (W_f - W_i)$$

Equation 4-2

where:
K_2 = 0.001335 m^3/g for metric units
= 0.04715 ft^3/g for English units

2.3.4 Sample gas volume.

$$V_{m(std)} = V_m Y \frac{(P_m)(T_{std})}{(P_{std})(T_m)} = K_3 Y \frac{V_m P_m}{T_m}$$

Equation 4-3

where:
K_3 = 0.3858 °K/mm Hg for metric units
= 17.64 °R/in. Hg for English units

NOTE.—If the post-test leak rate (Section 2.2.6) exceeds the allowable rate, correct the value of V_m in Equation 4-3, as described in Section 6.3 of Method 5.

2.3.5 Moisture Content.

$$B_{ws} = \frac{V_{wc(std)} + V_{wsg(std)}}{V_{wc(std)} + V_{wsg(std)} + V_{m(std)}}$$

Equation 4-4

NOTE.—In saturated or moisture droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one using a value based upon the saturated conditions (see Section 1.2), and another based upon the results of the impinger analysis. The lower of these two values of B_{ws} shall be considered correct.

2.3.6 Verification of constant sampling rate. For each time increment, determine the ΔV_m. Calculate the average. If the value for any time increment differs from the average by more than 10 percent, reject the results and repeat the run.

3. *Approximation Method*

The approximation method described below is presented only as a suggested method (see Section 1.2).

3.1 Apparatus.

3.1.1 Probe. Stainless steel or glass tubing, sufficiently heated to prevent water condensation and equipped with a filter (either in-stack or heated out-stack) to remove particulate matter. A plug of glass wool, inserted into the end of the probe, is a satisfactory filter.

3.1.2 Impingers. Two midget impingers, each with 30 ml capacity, or equivalent.

3.1.3 Ice Bath. Container and ice, to aid in condensing moisture in impingers.

3.1.4 Drying Tube. Tube packed with new or regenerated 6- to 16-mesh indicating-type silica gel (or equivalent desiccant), to dry the sample gas and to protect the meter and pump.

3.1.5 Valve. Needle valve, to regulate the sample gas flow rate.

3.1.6 Pump. Leak-free, diaphragm type, or equivalent, to pull the gas sample through the train.

3.1.7 Volume meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2%, and calibrated over the range of flow rates and conditions actually encountered during sampling.

3.1.8 Rate Meter. Rotameter, to measure the flow range from 0 to 3 l pm (0 to 0.11 cfm).[87]

3.1.9 Graduated Cylinder. 25 ml.

3.1.10 Barometer. Mercury, aneroid, or other barometer, as described in Section 2.1.5 above.

3.1.11 Vacuum Gauge. At least 760 mm Hg (30 in. Hg) gauge, to be used for the sampling leak check.

3.2 Procedure.

3.2.1 Place exactly 5 ml distilled water in each impinger. Leak check the sampling train as follows: Temporarily insert a vacuum gauge at or near the probe inlet; then, plug the probe inlet and pull a vacuum of at least 250 mm Hg (10 in. Hg). Note, the time rate of change of the dry gas meter dial; alternatively, a rotameter (0-40 cc/min) may be temporarily attached to the dry gas meter outlet to determine the leakage rate. A leak rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE.—Carefully release the probe inlet plug before turning off the pump.[87]

3.2.2 Connect the probe, insert it into the stack, and sample at a constant rate of 2 lpm (0.071 cfm). Continue sampling until the dry gas meter registers about 30 liters (1.1 ft^3) or until visible liquid droplets are carried over from the first impinger to the second. Record temperature, pressure, and dry gas meter readings as required by Figure 4-5.

3.2.3 After collecting the sample, combine the contents of the two impingers and measure the volume to the nearest 0.5 ml.

3.3 Calculations. The calculation method presented is designed to estimate the moisture in the stack gas; therefore, other data, which are only necessary for accurate moisture determinations, are not collected. The following equations adequately estimate the moisture content, for the purpose of determining isokinetic sampling rate settings.

3.3.1 Nomenclature.

B_{wm} = Approximate proportion, by volume, of water vapor in the gas stream leaving the second impinger, 0.025.
B_{ws} = Water vapor in the gas stream, proportion by volume.
M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole)
P_m = Absolute pressure (for this method, same as barometric pressure) at the dry gas meter.
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R = Ideal gas constant, 0.06236 (mm Hg) (m^3)/(g-mole) (°K) for metric units and 21.85 (in. Hg) (ft^3)/lb-mole) (°R) for English units.
T_m = Absolute temperature at meter, °K (°R)
T_{std} = Standard absolute temperature, 293° K (528° R)
V_f = Final volume of impinger contents, ml.
V_i = Initial volume of impinger contents, ml.
V_m = Dry gas volume measured by dry gas meter, dcm (dcf).
$V_{m(std)}$ = Dry gas volume measured by dry gas meter, corrected to standard conditions, dscm (dscf).
$V_{wc(std)}$ = Volume of water vapor condensed, corrected to standard conditions, scm (scf).
ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).
Y = Dry gas meter calibration factor.[87]

3.3.2 Volume of water vapor collected.

$$V_{wc} = \frac{(V_f - V_i)\rho_w R T_{std}}{P_{std} M_w} = K_1 (V_f - V_i)$$

Equation 4-5

where:
K_1 = 0.001333 m^3/ml for metric units
= 0.04707 ft^3/ml for English units.

3.3.3 Gas volume.

$$V_{m(std)} = V_m Y \left(\frac{P_m}{P_{std}}\right)\left(\frac{T_{std}}{T_m}\right) = K_3 Y \frac{V_m P_m}{T_m}$$

Equation 4-6[87]

where:
K_3 = 0.3858 °K/mm Hg for metric units
= 17.64 °R/in. Hg for English units

3.3.4 Approximate moisture content.

$$B_{ws} = \frac{V_{wc(std)}}{V_{wc(std)} + V_{m(std)}} + B_{wm}$$

$$\frac{V_{wc(std)}}{V_{wc(std)} + V_{m(std)}} + (0.025)$$

Equation 4-7[87]

4. *Calibration*

4.1 For the reference method, calibrate equipment as specified in the following sections of Method 5: Section 5.3 (metering system); Section 5.5 (temperature gauges); and Section 5.7 (barometer). The recommended leak check of the metering system (Section 5.6 of Method 5) also applies to the reference method. For the approximation method, use the procedures outlined in Section 5.1.1 of Method 6 to calibrate the metering system, and the procedure of Method 5, Section 5.7 to calibrate the barometer.

5. *Bibliography*

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2. Devorkin, Howard, et al. Air Pollution Source Testing Manual. Air Pollution Control District, Los Angeles, Calif. November, 1963.

3. Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases. Western Precipitation Division of Joy Manufacturing Co., Los Angeles, Calif. Bulletin WP-50. 1968.

Method 5—Determination of Particulate Emissions From Stationary Sources

1. *Principle and Applicability*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature in the range of 120±14° C (248±25° F) or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator, U.S. Environmental Protection Agency, for a particular application. The particulate mass, which includes any material that condenses at or above the filtration temperature, is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method is applicable for the determination of particulate emissions from stationary sources.

2. *Apparatus*

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 5–1. Complete construction details are given in APTD–0581 (Citation 2 in Section 7); commercial models of this train are also available. For changes from APTD–0581 and for allowable modifications of the train shown in Figure 5–1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD–0576 (Citation 3 in Section 7). Since correct usage is important in obtaining valid results, all users should read APTD–0576 and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass with sharp, tapered leading edge. The angle of taper shall be ≤30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing; other materials of construction may be used, subject to the approval of the Administrator.

A range of nozzle sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (⅛ to ½ in.)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in Section 5.

2.1.2 Probe Liner. Borosilicate or quartz glass tubing with a heating system capable of maintaining a gas temperature at the exit end during sampling of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. (The tester may opt to operate the equipment at a temperature lower than that specified.) Since the actual temperature at the outlet of the probe is not usually monitored during sampling, probes constructed according to APTD–0581 and utilizing the calibration curves of APTD–0576 (or calibrated according to the procedure outlined in APTD–0576) will be considered acceptable.

Either borosilicate or quartz glass probe liners may be used for stack temperatures up to about 480° C (900° F); quartz liners shall be used for temperatures between 480 and 900° C (900 and 1,650° F). Both types of liners may be used at higher temperatures than specified for short periods of time, subject to the approval of the Administrator. The softening temperature for borosilicate is 820° C (1,508° F), and for quartz it is 1,500° C (2,732° F).

Whenever practical, every effort should be made to use borosilicate or quartz glass probe liners. Alternatively, metal liners (e.g., 316 stainless steel, Incoloy 825,[1] or other corrosion resistant metals) made of seamless tubing may be used, subject to the approval of the Administrator.

2.1.3 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator. The pitot tube shall be attached to the probe (as shown in Figure 5–1) to allow constant monitoring of the stack gas velocity. The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane (see Method 2, Figure 2–6b) during sampling. The Type S pitot tube assembly shall have a known coefficient, determined as outlined in Section 4 of Method 2.

2.1.4 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.5 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other materials of construction (e.g., stainless steel, Teflon, Viton) may be used, subject to approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The holder shall be attached immediately at the outlet of the probe (or cyclone, if used).

2.1.6 Filter Heating System. Any heating system capable of maintaining a temperature around the filter holder during sampling of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. Alternatively, the tester may opt to operate the equipment at a temperature lower than that specified. A temperature gauge capable of measuring temperature to within 3° C (5.4° F) shall be installed so that the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD–0581 may be used.

2.1.7 Condenser. The following system shall be used to determine the stack gas moisture content: Four impingers connected in series with leak-free ground glass fittings or any similar leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with 1.3 cm (½ in.) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator. The first and second impingers shall contain known quantities of water (Section 4.1.3), the third shall be empty, and the fourth shall contain a known weight of silica gel, or equivalent desiccant. A thermometer, capable of measur-

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[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

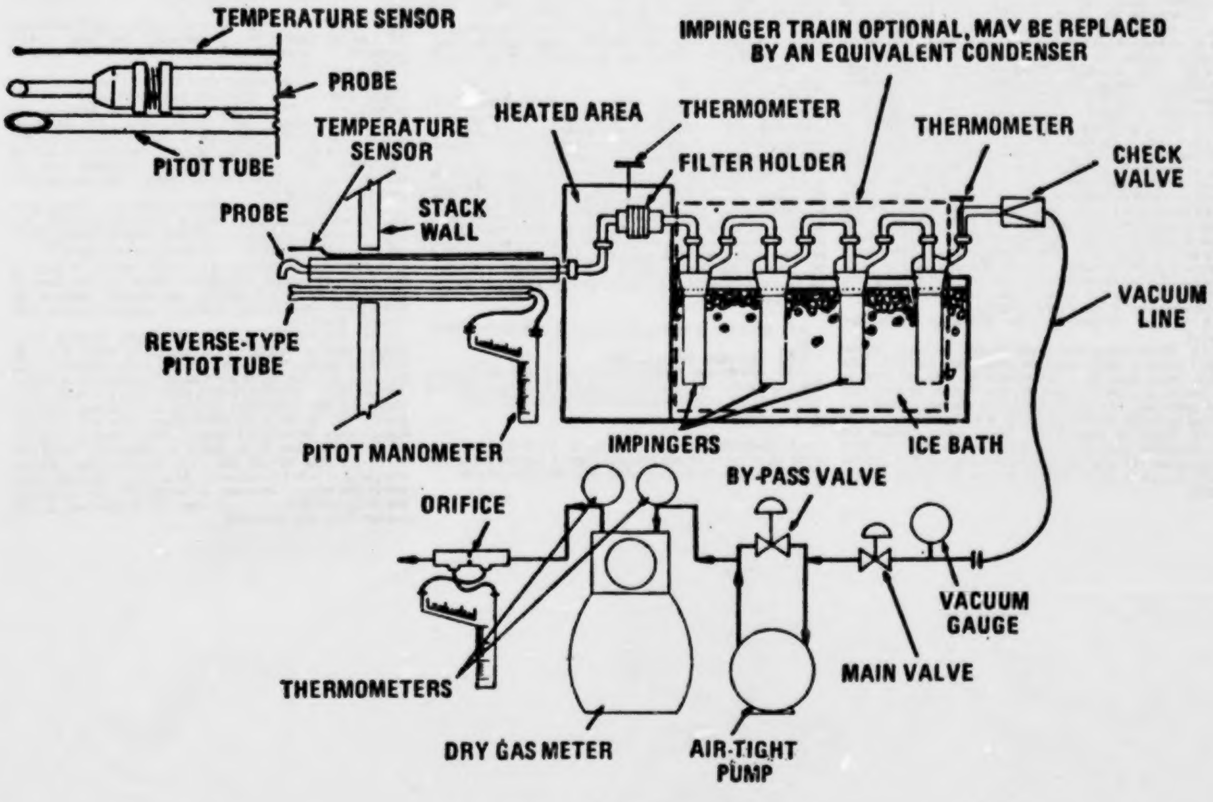

Figure 5 1. Particulate-sampling train.

ing temperature to within 1° C (2° F) shall be placed at the outlet of the fourth impinger for monitoring purposes.

Alternatively, any system that cools the sample gas stream and allows measurement of the water condensed and moisture leaving the condenser, each to within 1 ml or 1 g may be used, subject to the approval of the Administrator. Acceptable means are to measure the condensed water either gravimetrically or volumetrically and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap with exit gases kept below 20° C (68° F) and determining the weight gain.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

NOTE.—If a determination of the particulate matter collected in the impingers is desired in addition to moisture content, the impinger system described above shall be used, without modification. Individual States or control agencies requiring this information shall be contacted as to the sample recovery and analysis of the impinger contents.

2.1.8 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 5-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.9 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.10 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3. The temperature sensor shall, preferably, be permanently attached to the pitot tube or sampling probe in a fixed configuration, such that the tip of the sensor extends beyond the leading edge of the probe sheath and does not touch any metal. Alternatively, the sensor may be attached just prior to use in the field. Note, however, that if the temperature sensor is attached in the field, the sensor must be placed in an interference-free arrangement with respect to the Type S pitot tube openings (see Method 2, Figure 2-7). As a second alternative, if a difference of not more than 1 percent in the average velocity measurement is to be introduced, the temperature gauge need not be attached to the probe or pitot tube. (This alternative is subject to the approval of the Administrator.)

2.2 Sample Recovery. The following items are needed:

2.2.1 Probe-Liner and Probe-Nozzle Brushes. Nylon bristle brushes with stainless steel wire handles. The probe brush shall have extensions (at least as long as the probe) of stainless steel, Nylon, Teflon, or similarly inert material. The brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples, glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air-tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethlene, to aid in sample recovery.

2.3 Analysis. For analysis, the following equipment is needed.

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 g.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. *Reagents*

3.1 Sampling. The reagents used in sampling are as follows:

3.1.1 Filters. Glass fiber filters, without organic binder, exhibiting at least 99.95 percent efficiency (≤0.05 percent penetration) on 0.3-micron dioctyl phthalate smoke particles. The filter efficiency test shall be conducted in accordance with ASTM standard method D 2986-71. Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2 Silica Gel. Indicating type, 6 to 16 mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Water. When analysis of the material caught in the impingers is required, distilled water shall be used. Run blanks prior to field use to eliminate a high blank on test samples.

3.1.4 Crushed Ice.

3.1.5 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone—reagent grade, ≤0.001 percent residue, in glass bottles—is required. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers; thus, acetone blanks shall be run prior to field use and only acetone with low blank values (≤0.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis. Two reagents are required for the analysis:

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. *Procedure*

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

4.1.1 Pretest Preparation. All the components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper diameter on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., <0.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particulate sample run.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a suitable probe liner and probe length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 min (or some greater time interval as specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors. The sampling time at each point shall be the same.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as to prevent the sample gas stream from circumventing the filter. Check the filter for tears after assembly is completed.

When glass liners are used, install the selected nozzle using a Viton A O-ring when stack temperatures are less than 260° C (500° F) and an asbestos string gasket when temperatures are higher. See APTD-0576 for details. Other connecting systems using either 316 stainless steel or Teflon ferrules may be used. When metal liners are used, install the nozzle as above or by a leak-free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Set up the train as in Figure 5-1, using (if necessary) a very light coat of silicone grease on all ground glass joints, greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Subject to the approval of the Administrator, a glass cyclone may be used between the probe and filter holder when the total particulate catch is expected to exceed 100 mg or when water droplets are present in the stack gas.

Place crushed ice around the impingers.

4.1.4 Leak-Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, turn on and set the filter and probe heating systems at the desired operating temperatures. Allow time for the temperatures to stabilize. If a Viton A O-ring or other leak-free connection is used in assembling the probe nozzle to the probe liner, leak-check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum.

NOTE.—A lower vacuum may be used, provided that it is not exceeded during the test.

If an asbestos string is used, do not connect the probe to the train during the leak-check. Instead, leak-check the train by first plugging the inlet to the filter holder (cyclone, if applicable) and pulling a 380 mm Hg (15 in. Hg) vacuum (see Note immediately above). Then connect the probe to the train and leak-check at about 25 mm Hg (1 in. Hg) vacuum; alternatively, the probe may be leak-checked with the rest of the sampling train, in one step, at 380 mm Hg (15 in. Hg) vacuum. Leakage rates in excess of 4 percent of the average sampling rate or 0.00057 m^3/min (0.02 cfm), whichever is less, are unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with bypass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the bypass valve until the desired vacuum is reached. Do not reverse direction of bypass valve; this will cause water to back up into the filter holder. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe, filter holder, or cyclone (if applicable) and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder and silica gel from being entrained backward into the third impinger.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run. 5/

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain an isokinetic sampling rate (within 10 percent of true isokinetic unless otherwise specified by the Administrator) and a temperature around the filter of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator.

For each run, record the data required on a data sheet such as the one shown in Figure 5-2. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted.

PLANT ____________________
LOCATION ____________________
OPERATOR ____________________
DATE ____________________
RUN NO. ____________________
SAMPLE BOX NO. ____________________
METER BOX NO. ____________________
METER $\Delta H_@$ ____________________
C FACTOR ____________________
PITOT TUBE COEFFICIENT, C_p ____________________

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE ____________________
BAROMETRIC PRESSURE ____________________
ASSUMED MOISTURE, % ____________________
PROBE LENGTH, m (ft) ____________________
NOZZLE IDENTIFICATION NO. ____________________
AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) ____________________
PROBE HEATER SETTING ____________________
LEAK RATE, m^3/min.(cfm) ____________________
PROBE LINER MATERIAL ____________________
STATIC PRESSURE, mm Hg (in. Hg) ____________________
FILTER NO. ____________________

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_S) °C (°F)	VELOCITY HEAD (ΔP_S), mm (in.) H_2O	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER mm H_2O (in. H_2O)	GAS SAMPLE VOLUME m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		FILTER HOLDER TEMPERATURE, °C (°F)	TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET °C (°F)	OUTLET °C (°F)		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 5-2. Particulate field data.

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best available copy.

Take other readings required by Figure 5-2 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

Clean the portholes prior to the test run to minimize the chance of sampling deposited material. To begin sampling, remove the nozzle cap, verify that the filter and probe heating systems are up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85±0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29±4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges do not use the nomographs unless appropriate steps (see Citation 7 in Section 7) are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to prevent water from backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross-section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes; this minimizes the chance of extracting deposited material.

During the test run, make periodic adjustments to keep the temperature around the filter holder at the proper level; add more ice and, if necessary, salt to maintain a temperature of less than 20° C (68° F) at the condenser/silica gel outlet. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. Before a new filter assembly is installed, conduct a leak-check (see Section 4.1.4.2). The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator.

Note that when two or more trains are used, separate analyses of the front-half and (if applicable) impinger catches from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case, the front-half catches from the individual trains may be combined (as may the impinger catches) and one analysis of front-half catch and one analysis of impinger catch may be performed. Consult with the Administrator for details concerning the calculation of results when two or more trains are used.

At the end of the sample run, turn off the coarse adjust valve, remove the probe and nozzle from the stack, turn off the pump, record the final dry gas meter reading, and conduct a post-test leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Method 2, Section 3.1; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Calculations, Section 6) to determine whether the run was valid or another test run should be made. If there was difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period. Allow the probe to cool.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter holder.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. If a flexible line is used between the first impinger or condenser and the filter holder, disconnect the line at the filter holder and let any condensed water or liquid drain into the impingers or condenser. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Either ground-glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, probe fitting, probe liner, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow the Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until the acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone.

Brush and rinse the inside parts of the Swagelok fitting with acetone in a similar way until no visible particles remain.

Rinse the probe liner with acetone by tilting and rotating the probe while squirting acetone into its upper end so that all inside surfaces will be wetted with acetone. Let the acetone drain from the lower end into the sample container. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Follow the acetone rinse with a probe brush. Hold the probe in an inclined position, squirt acetone into the upper end as the probe brush is being pushed with a twisting action through the probe; hold a sample container underneath the lower end of the probe, and catch any acetone and particulate matter which is brushed from the probe. Run the brush through the probe three times or more until no visible particulate matter is carried out with the acetone or until none remains in the probe liner on visual inspection. With stainless steel or other metal probes, run the brush through in the above prescribed manner at least six times since metal probes have small crevices in which particulate matter can be entrapped. Rinse the brush with acetone, and quantitatively collect these washings in the sample container. After the brushing, make a final acetone rinse of the probe as described above.

It is recommended that two people be used to clean the probe to minimize sample losses. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints have been wiped clean of silicone grease, clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make a final rinse of the brush and filter holder. Carefully rinse out the glass cyclone, also (if applicable). After all acetone washings and particulate matter have been collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents.

Container No. 3. Note the color of the indicating silica gel to determine if it has been completely spent and make a notation of its condition. Transfer the silica gel from the fourth impinger to its original container and seal. A funnel may make it easier to pour the silica gel without spilling. A rubber policeman may be used as an aid in removing the silica gel from the impinger. It is not necessary to remove the small amount of dust particles that may adhere to the impinger wall and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for container No. 3 in Section 4.3.

Impinger Water. Treat the impingers as follows: Make a notation of any color or film in the liquid catch. Measure the liquid which is in the first three impingers to within ±1 ml by using a graduated cylinder or by weighing it to within ±0.5 g by using a balance (if one is available). Record the volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas.

Discard the liquid after measuring and recording the volume or weight, unless analysis of the impinger catch is required (see Note, Section 2.1.7).

If a different type of condenser is used, measure the amount of moisture condensed either volumetrically or gravimetrically.

Whenever possible, containers should be shipped in such a way that they remain upright at all times.

4.3 Analysis. Record the data required on a sheet such as the one shown in Figure 5-3. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at 105° C (220° F) for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at 105° C (220° F) for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. This step may be conducted in the field.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

NOTE.—At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. *Calibration*

Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. The Type S pitot tube assembly shall be calibrated according to the procedure outlined in Section 4 of Method 2.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD-0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values. Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m^3/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m^3/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD-0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

NOTE.—If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Probe Heater Calibration. The probe heating system shall be calibrated before its initial use in the field according to the procedure outlined in APTD-0576. Probes constructed according to APTD-0561 need not be calibrated if the calibration curves in APTD-0576 are used.

5.5 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.6 Leak Check of Metering System Shown in Figure 5-1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 5-4): Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

5.7 Barometer. Calibrate against a mercury barometer.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

Plant ________________

Date ________________

Run No. ________________

Filter No. ________________

Amount liquid lost during transport ________________

Acetone blank volume, ml ________________

Acetone wash volume, ml ________________

Acetone blank concentration, mg/mg (equation 5-4) ________________

Acetone wash blank, mg (equation 5-5) ________________

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL			

Less acetone blank	
Weight of particulate matter	

	VOLUME OF LIQUID WATER COLLECTED	
	IMPINGER VOLUME, ml.	SILICA GEL WEIGHT, g
FINAL		
INITIAL		
LIQUID COLLECTED		
TOTAL VOLUME COLLECTED		g* ml

* CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER (1g/ml).

$$\frac{\text{INCREASE, g}}{1\ \text{g/ml}} = \text{VOLUME WATER, ml}$$

Figure 5-3. Analytical data.

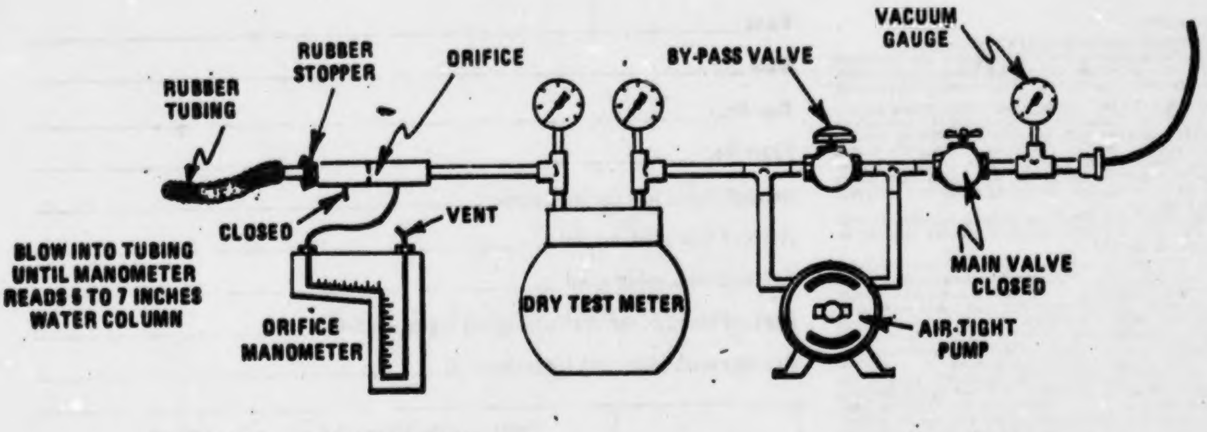

Figure 5-4. Leak check of meter box.

6.1 Nomenclature

A_n = Cross-sectional area of nozzle, m² (ft²).

B_{ws} = Water vapor in the gas stream, proportion by volume. 87

C_a = Acetone blank residue concentration, mg/g.

c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).

I = Percent of isokinetic sampling.

L_a = Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m³/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.

L_i = Individual leakage rate observed during the leak check conducted prior to the "i^{th}" component change (i=1, 2, 3 . . . . n), m³/min (cfm).

L_p = Leakage rate observed during the post-test leak check, m³/min (cfm).

m_n = Total amount of particulate matter collected, mg.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

m_a = Mass of residue of acetone after evaporation, mg.

P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 mm Hg-m³/°K-g-mole (21.85 in. Hg-ft³/°R-lb-mole).

T_m = Absolute average dry gas meter temperature (see Figure 5-2), °K (°R).

T_s = Absolute average stack gas temperature (see Figure 5-2), °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R).

V_a = Volume of acetone blank, ml.

V_{aw} = Volume of acetone used in wash, ml.

V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 5-3), ml.

V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).

v_s = Stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 5, m/sec (ft/sec). 87

W_a = Weight of residue in acetone wash, mg.

Y = Dry gas meter calibration factor.

ΔH = Average pressure differential across the orifice meter (see Figure 5-2), mm H₂O (in. H₂O).

ρ_a = Density of acetone, mg/ml (see label on bottle).

ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).

θ = Total sampling time, min.

θ_1 = Sampling time interval, from the beginning of a run until the first component change, min.

θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.

13.6 = Specific gravity of mercury.

60 = Sec/min.

100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 5-2).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 5-1.

$$V_{m(std)}=V_mY\left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar}+\frac{\Delta H}{13.6}}{P_{std}}\right]$$

$$=K_1V_mY\,\frac{P_{bar}+(\Delta H/13.6)}{T_m}$$

Equation 5-1

where:

K_1 = 0.3858 °K/mm Hg for metric units 87
= 17.64 °R/in. Hg for English units

NOTE.—Equation 5-1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 5-1 must be modified as follows;

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 5-1 with the expression;

$$V_m-(L_p-L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 5-1 by the expression:

$$\left[V_m-(L_1-L_a)\theta_1-\sum_{i=2}^{n}(L_i-L_a)\theta_i-(L_p-L_a)\theta_p\right]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

Equation 5-2

$$V_{w(std)}=V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right)=K_2V_{lc}$$

where:

K_2 = 0.001333 m³/ml for metric units
= 0.04707 ft³/ml for English units.

6.5 Moisture Content.

$$B_{ws}=\frac{V_{w(std)}}{V_{m(std)}+V_{w(std)}}$$

Equation 5-3

NOTE.—In saturated or water droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one from the impinger analysis (Equation 5-3), and a second from the assumption of saturated conditions. The lower of the two values of B_{ws} shall be considered correct. The procedure for determining the moisture content based upon assumption of saturated conditions is given in the Note of Section 1.2 of Method 4. For the purposes of this method, the average stack gas temperature from Figure 5-2 may be used to make this determination, provided that the accuracy of the in-stack temperature sensor is ± 1° C (2° F).

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a}$$

Equation 5-4

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a$$

Equation 5-5

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 5-6). NOTE.—Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001\ g/mg)\ (m_n/V_{m(std)})$$

Equation 5-6

6.10 Conversion Factors:

From	To	Multiply by
scf	m³	0.02832
g/ft³	gr/ft³	15.43
g/ft³	lb/ft³	2.205×10^{-3}
g/ft³	g/m³	35.31

6.11 Isokinetic Variation.

6.11.1 Calculation From Raw Data.

$$I = \frac{100\ T_s [K_3 V_{lc} + (V_m Y/T_m)\ (P_{bar} + \Delta H/13.6)]}{60\ \theta v_s P_s A_n}$$

Equation 5-7

87

where:

K_3=0.003454 mm Hg−m³/ml−°K for metric units.

=0.002669 in. Hg−ft³/ml−°R for English units.

6.11.2 Calculation From Intermediate Values.

$$I = \frac{T_s V_{m(std)} P_{std} 100}{T_{std} v_s \theta A_n P_s 60 (1 - B_{ws})}$$

$$= K_4 \frac{T_s V_{m(std)}}{P_s V_s A_n \theta (1 - B_{ws})}$$

Equation 5-8

where:

K_4= 4.320 for metric units

=0.09450 for English units.

6.12 Acceptable Results. If 90 percent ≤ I ≤ 110 percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography*

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METHOD 6—DETERMINATION OF SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted from the sampling point in the stack. The sulfuric acid mist (including sulfur trioxide) and the sulfur dioxide are separated. The sulfur dioxide fraction is measured by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfur dioxide emissions from stationary sources. The minimum detectable limit of the method has been determined to be 3.4 milligrams (mg) of SO_2/m^3 (2.12×10^{-7} lb/ft^3). Although no upper limit has been established, tests have shown that concentrations as high as 80,000 mg/m^3 of SO_2 can be collected efficiently in two midget impingers, each containing 15 milliliters of 3 percent hydrogen peroxide, at a rate of 1.0 lpm for 20 minutes. Based on theoretical calculations, the upper concentration limit in a 20-liter sample is about 93,300 mg/m^3.

Possible interferents are free ammonia, water-soluble cations, and fluorides. The cations and fluorides are removed by glass wool filters and an isopropanol bubbler, and hence do not affect the SO_2 analysis. When samples are being taken from a gas stream with high concentrations of very fine metallic fumes (such as in inlets to control devices), a high-efficiency glass fiber filter must be used in place of the glass wool plug (i.e., the one in the probe) to remove the cation interferents.

Free ammonia interferes by reacting with SO_2 to form particulate sulfite and by reacting with the indicator. If free ammonia is present (this can be determined by knowledge of the process and noticing white particulate matter in the probe and isopropanol bubbler), alternative methods, subject to the approval of the Administrator, U.S. Environmental Protection Agency, are required.

2. *Apparatus*

2.1 Sampling. The sampling train is shown in Figure 6-1, and component parts are discussed below. The tester has the option of substituting sampling equipment described in Method 8 in place of the midget impinger equipment of Method 6. However, the Method 8 train must be modified to include a heated filter between the probe and isopropanol impinger, and the operation of the sampling train and sample analysis must be at the flow rates and solution volumes defined in Method 8.

The tester also has the option of determining SO_2 simultaneously with particulate matter and moisture determinations by (1) replacing the water in a Method 5 impinger system with 3 percent peroxide solution, or (2) by replacing the Method 5 water impinger system with a Method 8 isopropanol-filter-peroxide system. The analysis for SO_2 must be consistent with the procedure in Method 8. 87

2.1.1 Probe. Borosilicate glass, or stainless steel (other materials of construction may be used, subject to the approval of the Administrator), approximately 6-mm inside diameter, with a heating system to prevent water condensation and a filter (either in-stack or heated out-stack) to remove particulate matter, including sulfuric acid mist. A plug of glass wool is a satisfactory filter.

2.1.2 Bubbler and Impingers. One midget bubbler, with medium-coarse glass frit and borosilicate or quartz glass wool packed in top (see Figure 6-1) to prevent sulfuric acid mist carryover, and three 30-ml midget impingers. The bubbler and midget impingers must be connected in series with leak-free glass connectors. Silicone grease may be used, if necessary, to prevent leakage.

At the option of the tester, a midget impinger may be used in place of the midget bubbler.

Other collection absorbers and flow rates may be used, but are subject to the approval of the Administrator. Also, collection efficiency must be shown to be at least 99 percent for each test run and must be documented in the report. If the efficiency is found to be acceptable after a series of three tests, further documentation is not required. To conduct the efficiency test, an extra absorber must be added and analyzed separately. This extra absorber must not contain more than 1 percent of the total SO_2.

2.1.3 Glass Wool. Borosilicate or quartz.

2.1.4 *Stopcock* Grease. Acetone-insoluble, heat-stable silicone grease may be used, if necessary.

2.1.5 Temperature Gauge. Dial thermometer, or equivalent, to measure temperature of gas leaving impinger train to within 1° C (2° F.)

2.1.6 Drying Tube. Tube packed with 6- to 16-mesh indicating type silica gel, or equivalent, to dry the gas sample and to protect the meter and pump. If the silica gel has been used previously, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to approval of the Administrator. 87

2.1.7 Valve. Needle valve, to regulate sample gas flow rate. 87

2.1.8 Pump. Leak-free diaphragm pump, or equivalent, to pull gas through the train. Install a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter. 87

2.1.9 Rate Meter. Rotameter, or equivalent, capable of measuring flow rate to within 2 percent of the selected flow rate of about 1000 cc/min.

2.1.10 Volume Meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature gauge (dial thermometer, or equivalent) capable of measuring temperature to within 3°C (5.4°F).

2.1.11 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease. 87

2.1.12 Vacuum Gauge and rotameter. At least 760 mm Hg (30 in. Hg) gauge, and 0–40 cc/min rotameter to be used for leak check of the sampling train. 87

2.2.1 Wash bottles. Polyethylene or glass, 500 ml, two.

2.2.2 Storage Bottles. Polyethylene, 100 ml, to store impinger samples (one per sample).

2.3 Analysis.

2.3.1 Pipettes. Volumetric type, 5-ml, 20-ml (one per sample), and 25-ml sizes.

2.3.2 Volumetric Flasks. 100-ml size (one per sample) and 1000-ml size. 87

2.3.3 Burettes. 5- and 50-ml sizes.

2.3.4 Erlenmeyer Flasks. 250 ml-size (one for each sample, blank, and standard).

2.3.5 Dropping Bottle. 125-ml size, to add indicator.

2.3.6 Graduated Cylinder. 100-ml size.

2.3.7 Spectrophotometer. To measure absorbance at 352 nanometers.

3. *Reagents*

Unless otherwise indicated, all reagents must conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society. Where such specifications are not available, use the best available grade.

3.1 Sampling.

3.1.1 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.1.2 Isopropanol, 80 percent. Mix 80 ml of isopropanol with 20 ml of deionized, distilled water. Check each lot of isopropanol for peroxide impurities as follows: shake 10 ml of isopropanol with 10 ml of freshly prepared 10 percent potassium iodide solution. Prepare a blank by similarly treating 10 ml of distilled water. After 1 minute, read the absorbance at 352 nanometers on a spectrophotometer. If absorbance exceeds 0.1, reject alcohol for use.

Peroxides may be removed from isopropanol by redistilling or by passage through a column of activated alumina; however, reagent grade isopropanol with suitably low peroxide levels may be obtained from commercial sources. Rejection of contaminated lots may, therefore, be a more efficient procedure.

3.1.3 Hydrogen Peroxide, 3 Percent. Dilute 30 percent hydrogen peroxide 1:9 (v/v) with deionized, distilled water (30 ml is needed per sample). Prepare fresh daily.

3.1.4 Potassium Iodide Solution, 10 Percent. Dissolve 10.0 grams KI in deionized, distilled water and dilute to 100 ml. Prepare when needed.

3.2 Sample Recovery.

3.2.1 Water. Deionized, distilled, as in 3.1.1.

3.2.2 Isopropanol, 80 Percent. Mix 80 ml of isopropanol with 20 ml of deionized, distilled water.

3.3 Analysis.

3.3.1 Water. Deionized, distilled, as in 3.1.1.

3.3.2 Isopropanol, 100 percent.

3.3.3 Thorin Indicator. 1-(o-arsonophenylazo)-2-naphthol-3,6-disulfonic acid, disodium salt, or equivalent. Dissolve 0.20 g in 100 ml of deionized, distilled water.

3.3.4 Barium Perchlorate Solution, 0.0100 N. Dissolve 1.95 g of barium perchlorate trihydrate [$Ba(ClO_4)_2 \cdot 3H_2O$] in 200 ml distilled water and dilute to 1 liter with isopropanol. Alternatively, 1.22 g of [$BaCl_2 \cdot 2H_2O$] may be used instead of the perchlorate. Standardize as in Section 5.5. 87

3.3.5 Sulfuric Acid Standard, 0.0100 N. Purchase or standardize to ±0.0002 N against 0.0100 N NaOH which has previously been standardized against potassium acid phthalate (primary standard grade).

4. *Procedure*

4.1 Sampling.

4.1.1 Preparation of collection train. Measure 15 ml of 80 percent isopropanol into the midget bubbler and 15 ml of 3 percent hydrogen peroxide into each of the first two midget impingers. Leave the final midget impinger dry. Assemble the train as shown in Figure 6-1. Adjust probe heater to a temperature sufficient to prevent water condensation. Place crushed ice and water around the impingers.

4.1.2 Leak-check procedure. A leak check prior to the sampling run is optional; however, a leak check after the sampling run is mandatory. The leak-check procedure is as follows:

Temporarily attach a suitable (e.g., 0–40 cc/min) rotameter to the outlet of the dry gas meter and place a vacuum gauge at or near the probe inlet. Plug the probe inlet, pull a vacuum of at least 250 mm Hg (10 in. Hg), and note the flow rate as indicated by the rotameter. A leakage rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE: Carefully release the probe inlet plug before turning off the pump.

It is suggested (not mandatory) that the pump be leak-checked separately, either prior to or after the sampling run. If done prior to the sampling run, the pump leak-check shall precede the leak check of the sampling train described immediately above; if done after the sampling run, the pump leak-check shall follow the train leak-check. To leak check the pump, proceed as follows: Disconnect the drying tube from the probe-impinger assembly. Place a vacuum gauge at the inlet to either the drying tube or the pump, pull a vacuum of 250 mm (10 in.) Hg, plug or pinch off the outlet of the flow meter and then turn off the pump. The vacuum should remain stable for at least 30 seconds. 87

Other leak check procedures may be used, subject to the approval of the Administrator, U.S. Environmental Protection Agency. The procedure used in Method 5 is not suitable for diaphragm pumps.

4.1.3 Sample collection. Record the initial dry gas meter reading and barometric pressure. To begin sampling, position the tip of the probe at the sampling point, connect the probe to the bubbler, and start the pump. Adjust the sample flow to a constant rate of approximately 1.0 liter/min as indicated by the rotameter. Maintain this constant rate (±10 percent) during the entire sampling run. Take readings (dry gas meter, temperatures at dry gas meter and at impinger outlet and rate meter) at least every 5 minutes. Add more ice during the run to keep the temperature of the gases leaving the last impinger at 20° C (68° F) or less. At the conclusion of each run, turn off the pump, remove probe from the stack, and record the final readings. Conduct a leak check as in Section 4.1.2. (This leak check is mandatory.) If a leak is found, void the test run, or use procedures acceptable to the Administrator to adjust the sample volume for the leakage. Drain the ice bath, and purge the remaining part of the train by drawing clean ambient air through the system for 15 minutes at the sampling rate. 87

Clean ambient air can be provided by passing air through a charcoal filter or through an extra midget impinger with 15 ml of 3 percent H_2O_2. The tester may opt to simply use ambient air, without purification.

4.2 Sample Recovery. Disconnect the impingers after purging. Discard the contents of the midget bubbler. Pour the contents of the midget impingers into a leak-free polyethylene bottle for shipment. Rinse the three midget impingers and the connecting tubes with deionized, distilled water, and add the washings to the same storage container. Mark the fluid level. Seal and identify the sample container.

4.3 Sample Analysis. Note level of liquid in container, and confirm whether any sample was lost during shipment; note this on analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.

Transfer the contents of the storage container to a 100-ml volumetric flask and dilute to exactly 100 ml with deionized, distilled water. Pipette a 20-ml aliquot of this solution into a 250-ml Erlenmeyer flask, add 80 ml of 100 percent isopropanol and two to four drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat and average the titration volumes. Run a blank with each series of samples. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is larger.

(NOTE.—Protect the 0.0100 N barium perchlorate solution from evaporation at all times.)

5. *Calibration*

5.1 Metering System.

5.1.1 Initial Calibration. Before its initial use in the field, first leak check the metering system (drying tube, needle valve, pump, rotameter, and dry gas meter) as follows: place a vacuum gauge at the inlet to the drying tube and pull a vacuum of 250 mm (10 in.) Hg; plug or pinch off the outlet of the flow meter, and then turn off the pump. The vacuum shall remain stable for at least 30 seconds. Carefully release the vacuum gauge before releasing the flow meter end.

Next, calibrate the metering system (at the sampling flow rate specified by the method) as follows: connect an appropriately sized wet test meter (e.g., 1 liter per revolution) to the inlet of the drying tube. Make three independent calibration runs, using at least five revolutions of the dry gas meter per run. Calculate the calibration factor, Y (wet test meter calibration volume divided by the dry gas meter volume, both volumes adjusted to the same reference temperature and pressure), for each run, and average the results. If any Y value deviates by more than 2 percent from the average, the metering system is unacceptable for use. Otherwise, use the average as the calibration factor for subsequent test runs.

5.1.2 Post-Test Calibration Check. After each field test series, conduct a calibration check as in Section 5.1.1 above, except for the following variations: (a) the leak check is not to be conducted, (b) three, or more revolutions of the dry gas meter may be used, and (c) only two independent runs need be made. If the calibration factor does not deviate by more than 5 percent from the initial calibration factor (determined in Section 5.1.1), then the dry gas meter volumes obtained during the test series are acceptable. If the calibration factor deviates by more than 5 percent, recalibrate the metering system as in Section 5.1.1, and for the calculations, use the calibration factor (initial or recalibration) that yields the lower gas volume for each test run.

5.2 Thermometers. Calibrate against mercury-in-glass thermometers.

5.3 Rotameter. The rotameter need not be calibrated but should be cleaned and maintained according to the manufacturer's instruction.

5.4 Barometer. Calibrate against a mercury barometer.

5.5 Barium Perchlorate Solution. Standardize the barium perchlorate solution against 25 ml of standard sulfuric acid to which 100 ml of 100 percent isopropanol has been added.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

6.1 Nomenclature.

C_{SO_2} = Concentration of sulfur dioxide, dry basis corrected to standard conditions, mg/dscm (lb/dscf).
N = Normality of barium perchlorate titrant, milliequivalents/ml.
P_{bar} = Barometric pressure at the exit orifice of the dry gas meter, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
T_m = Average dry gas meter absolute temperature, °K (°R).
T_{std} = Standard absolute temperature, 293° K (528° R).
V_a = Volume of sample aliquot titrated, ml.
V_m = Dry gas volume as measured by the dry gas meter, dcm (dcf).
$V_{m(std)}$ = Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
V_{soln} = Total volume of solution in which the sulfur dioxide sample is contained, 100 ml.
V_t = Volume of barium perchlorate titrant used for the sample, ml (average of replicate titrations).
V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.
Y = Dry gas meter calibration factor.
32.03 = Equivalent weight of sulfur dioxide.

6.2 Dry sample gas volume, corrected to standard conditions.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar}}{P_{std}}\right) = K_1 Y \frac{V_m P_{bar}}{T_m}$$

Equation 6-1

where:

K_1 = 0.3858 °K/mm Hg for metric units.
= 17.64 °R/in. Hg for English units.

6.3 Sulfur dioxide concentration.

$$C_{SO_2} = K_2 \frac{(V_t - V_{tb})\, N\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 6-2

where:

K_2 = 32.03 mg/meq. for metric units.
= 7.061×10⁻⁵ lb/meq. for English units.

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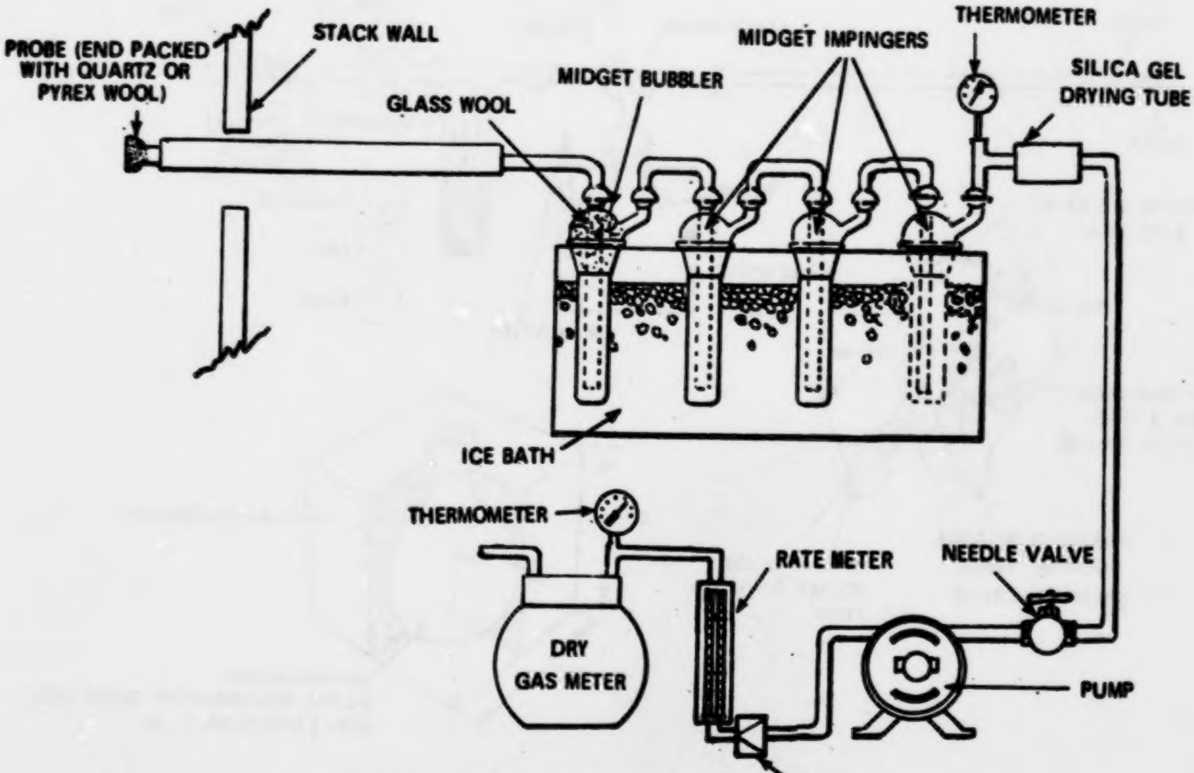

Figure 6-1. SO_2 sampling train.

METHOD 7—DETERMINATION OF NITROGEN OXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A grab sample is collected in an evacuated flask containing a dilute sulfuric acid-hydrogen peroxide absorbing solution, and the nitrogen oxides, except nitrous oxide, are measured colorimaterically using the phenoldisulfonic acid (PDS) procedure.

1.2 Applicability. This method is applicable to the measurement of nitrogen oxides emitted from stationary sources. The range of the method has been determined to be 2 to 400 milligrams NO_x (as NO_2) per dry standard cubic meter, without having to dilute the sample.

2. *Apparatus*

2.1 Sampling (see Figure 7-1). Other grab sampling systems or equipment, capable of measuring sample volume to within ±2.0 percent and collecting a sufficient sample volume to allow analytical reproducibility to within ±5 percent, will be considered acceptable alternatives, subject to approval of the Administrator, U.S. Environmental Protection Agency. The following equipment is used in sampling:

2.1.1 Probe. Borosilicate glass tubing, sufficiently heated to prevent water condensation and equipped with an in-stack or out-stack filter to remove particulate matter (a plug of glass wool is satisfactory for this purpose). Stainless steel or Teflon[1] tubing may also be used for the probe. Heating is not necessary if the probe remains dry during the purging period.

2.1.2 Collection Flask. Two-liter borosilicate, round bottom flask, with short neck and 24/40 standard taper opening, protected against implosion or breakage.

2.1.3 Flask Valve. T-bore stopcock connected to a 24/40 standard taper joint.

2.1.4 Temperature Gauge. Dial-type thermometer, or other temperature gauge, capable of measuring 1° C (2° F) intervals from −5 to 50° C (25 to 125° F).

2.1.5 Vacuum Line. Tubing capable of withstanding a vacuum of 75 mm Hg (3 in. Hg) absolute pressure, with "T" connection and T-bore stopcock.

2.1.6 Vacuum Gauge. U-tube manometer, 1 meter (36 in.), with 1-mm (0.1-in.) divisions, or other gauge capable of measuring pressure to within ±2.5 mm Hg (0.10 in. Hg).

2.1.7 Pump. Capable of evacuating the collection flask to a pressure equal to or less than 75 mm Hg (3 in. Hg) absolute.

2.1.8 Squeeze Bulb. One-way.

2.1.9 Volumetric Pipette. 25 ml.

2.1.10 Stopcock and Ground Joint Grease. A high-vacuum, high-temperature chlorofluorocarbon grease is required. Halocarbon 25-5S has been found to be effective.

2.1.11 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase, or vice versa for elevation decrease.

2.2 Sample Recovery. The following equipment is required for sample recovery:

2.2.1 Graduated Cylinder. 50 ml with 1-ml divisions.

2.2.2 Storage Containers. Leak-free polyethylene bottles.

2.2.3 Wash Bottle. Polyethylene or glass.

2.2.4 Glass Stirring Rod.

2.2.5 Test Paper for Indicating pH. To cover the pH range of 7 to 14.

2.3 Analysis. For the analysis, the following equipment is needed:

2.3.1 Volumetric Pipettes. Two 1 ml, two 2 ml, one 3 ml, one 4 ml, two 10 ml, and one 25 ml for each sample and standard.

2.3.2 Porcelain Evaporating Dishes. 175- to 250-ml capacity with lip for pouring, one for each sample and each standard. The Coors No. 45006 (shallow-form, 195 ml) has been found to be satisfactory. Alternatively, polymethyl pentene beakers (Nalge No. 1203, 150 ml), or glass beakers (150 ml) may be used. When glass beakers are used, etching of the beakers may cause solid matter to be present in the analytical step; the solids should be removed by filtration (see Section 4.3). B7

2.3.3 Steam Bath. Low-temperature ovens or thermostatically controlled hot plates kept below 70° C (160° F) are acceptable alternatives.

2.3.4 Dropping Pipette or Dropper. Three required.

2.3.5 Polyethylene Policeman. One for each sample and each standard.

2.3.6 Graduated Cylinder. 100 ml with 1-ml divisions.

2.3.7 Volumetric Flasks. 50 ml (one for each sample and each standard), 100 ml (one for each sample and each standard, and one for the working standard KNO_3 solution), and 1000 ml(one). B7

2.3.8 Spectrophotometer. To measure absorbance at 410 nm.

2.3.9 Graduated Pipette. 10 ml with 0.1-ml divisions.

2.3.10 Test Paper for Indicating pH. To cover the pH range of 7 to 14.

2.3.11 Analytical Balance. To measure to within 0.1 mg.

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[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

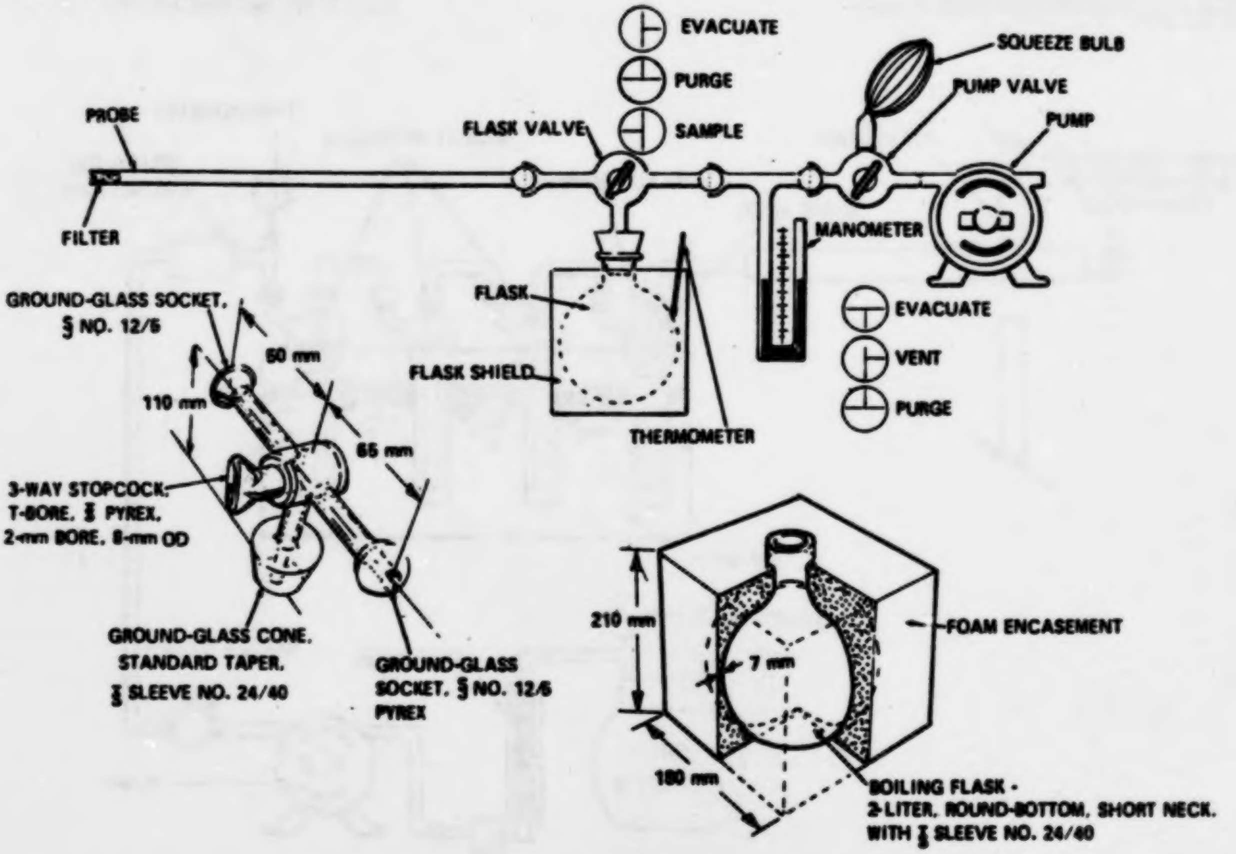
EVACUATE
PURGE
SAMPLE
SQUEEZE BULB
PUMP VALVE
PUMP
PROBE
FLASK VALVE
FILTER
MANOMETER
FLASK
GROUND-GLASS SOCKET, § NO. 12/5
60 mm
110 mm
65 mm
FLASK SHIELD
THERMOMETER
EVACUATE
VENT
PURGE
3-WAY STOPCOCK: T-BORE, § PYREX, 2-mm BORE, 8-mm OD
GROUND-GLASS CONE, STANDARD TAPER, § SLEEVE NO. 24/40
GROUND-GLASS SOCKET, § NO. 12/5 PYREX
210 mm
FOAM ENCASEMENT
7 mm
190 mm
BOILING FLASK - 2-LITER, ROUND-BOTTOM, SHORT NECK, WITH § SLEEVE NO. 24/40

Figure 7-1. Sampling train, flask valve, and flask.

3. *Reagents*

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

3.1 Sampling. To prepare the absorbing solution, cautiously add 2.8 ml concentrated H_2SO_4 to 1 liter of deionized, distilled water. Mix well and add 6 ml of 3 percent hydrogen peroxide, freshly prepared from 30 percent hydrogen peroxide solution. The absorbing solution should be used within 1 week of its preparation. Do not expose to extreme heat or direct sunlight.

3.2 Sample Recovery. Two reagents are required for sample recovery:

3.2.1 Sodium Hydroxide (1N). Dissolve 40 g NaOH in deionized, distilled water and dilute to 1 liter.

3.2.2 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.3 Analysis. For the analysis, the following reagents are required:

3.3.1 Fuming Sulfuric Acid. 15 to 18 percent by weight free sulfur trioxide. HANDLE WITH CAUTION.

3.3.2 Phenol. White solid.

3.3.3 Sulfuric Acid. Concentrated, 95 percent minimum assay. HANDLE WITH CAUTION.

3.3.4 Potassium Nitrate. Dried at 105 to 110° C (220 to 230° F) for a minimum of 2 hours just prior to preparation of standard solution.

3.3.5 Standard KNO_3 Solution. Dissolve exactly 2.198 g of dried potassium nitrate (KNO_3) in deionized, distilled water and dilute to 1 liter with deionized, distilled water in a 1,000-ml volumetric flask.

3.3.6 Working Standard KNO_3 Solution. Dilute 10 ml of the standard solution to 100 ml with deionized distilled water. One milliliter of the working standard solution is equivalent to 100 μg nitrogen dioxide (NO_2).

3.3.7 Water. Deionized, distilled as in Section 3.2.2.

3.3.8 Phenoldisulfonic Acid Solution. Dissolve 25 g of pure white phenol in 150 ml concentrated sulfuric acid on a steam bath. Cool, add 75 ml fuming sulfuric acid, and heat at 100° C (212° F) for 2 hours. Store in a dark, stoppered bottle.

4. *Procedures*

4.1 Sampling.

4.1.1 Pipette 25 ml of absorbing solution into a sample flask, retaining a sufficient quantity for use in preparing the calibration standards. Insert the flask valve stopper into the flask with the valve in the "purge" position. Assemble the sampling train as shown in Figure 7-1 and place the probe at the sampling point. Make sure that all fittings are tight and leak-free, and that all ground glass joints have been properly greased with a high-vacuum, high-temperature chlorofluorocarbon-based stopcock grease. Turn the flask valve and the pump valve to their "evacuate" positions. Evacuate the flask to 75 mm Hg (3 in. Hg) absolute pressure, or less. Evacuation to a pressure approaching the vapor pressure of water at the existing temperature is desirable. Turn the pump valve to its "vent" position and turn off the pump. Check for leakage by observing the manometer for any pressure fluctuation. (Any variation greater than 10 mm Hg (0.4 in. Hg) over a period of 1 minute is not acceptable, and the flask is not to be used until the leakage problem is corrected. Pressure in the flask is not to exceed 75 mm Hg (3 in. Hg) absolute at the time sampling is commenced.) Record the volume of the flask and valve (V_f), the flask temperature (T_i), and the barometric pressure. Turn the flask valve counterclockwise to its "purge" position and do the same with the pump valve. Purge the probe and the vacuum tube using the squeeze bulb. If condensation occurs in the probe and the flask valve area, heat the probe and purge until the condensation disappears. Next, turn the pump valve to its "vent" position. Turn the flask valve clockwise to its "evacuate" position and record the difference in the mercury levels in the manometer. The absolute internal pressure in the flask (P_i) is equal to the barometric pressure less the manometer reading. Immediately turn the flask valve to the "sample" position and permit the gas to enter the flask until pressures in the flask and sample line (i.e., duct, stack) are equal. This will usually require about 15 seconds; a longer period indicates a "plug" in the probe, which must be corrected before sampling is continued. After collecting the sample, turn the flask valve to its "purge" position and disconnect the flask from the sampling train. Shake the flask for at least 5 minutes.

4.1.2 If the gas being sampled contains insufficient oxygen for the conversion of NO to NO_2 (e.g., an applicable subpart of the standard may require taking a sample of a calibration gas mixture of NO in N_2), then oxygen shall be introduced into the flask to permit this conversion. Oxygen may be introduced into the flask by one of three methods; (1) Before evacuating the sampling flask, flush with pure cylinder oxygen, then evacuate flask to 75 mm Hg (3 in. Hg) absolute pressure or less; or (2) inject oxygen into the flask after sampling; or (3) terminate sampling with a minimum of 50 mm Hg (2 in. Hg) vacuum remaining in the flask, record this final pressure, and then vent the flask to the atmosphere until the flask pressure is almost equal to atmospheric pressure.

4.2 Sample Recovery. Let the flask set for a minimum of 16 hours and then shake the contents for 2 minutes. Connect the flask to a mercury filled U-tube manometer. Open the valve from the flask to the manometer and record the flask temperature (T_f), the barometric pressure, and the difference between the mercury levels in the manometer. The absolute internal pressure in the flask (P_f) is the barometric pressure less the manometer reading. Transfer the contents of the flask to a leak-free polyethylene bottle. Rinse the flask twice with 5-ml portions of deionized, distilled water and add the rinse water to the bottle. Adjust the pH to between 9 and 12 by adding sodium hydroxide (1 N), dropwise (about 25 to 35 drops). Check the pH by dipping a stirring rod into the solution and then touching the rod to the pH test paper. Remove as little material as possible during this step. Mark the height of the liquid level so that the container can be checked for leakage after transport. Label the container to clearly identify its contents. Seal the container for shipping. 87

4.3 Analysis. Note the level of the liquid in container and confirm whether or not any sample was lost during shipment; note this on the analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Immediately prior to analysis, transfer the contents of the shipping container to a 50-ml volumetric flask, and rinse the container twice with 5-ml portions of deionized, distilled water. Add the rinse water to the flask and dilute to the mark with deionized, distilled water; mix thoroughly. Pipette a 25-ml aliquot into the procelain evaporating dish. Return any unused portion of the sample to the polyethylene storage bottle. Evaporate the 25-ml aliquot to dryness on a steam bath and allow to cool. Add 2 ml phenoldisulfonic acid solution to the dried residue and triturate thoroughly with a polyethylene policeman. Make sure the solution contacts all the residue. Add 1 ml deionized, distilled water and four drops of concentrated sulfuric acid. Heat the solution on a steam bath for 3 minutes with occasional stirring. Allow the solution to cool, add 20 ml deionized, distilled water, mix well by stirring, and add concentrated ammonium hydroxide, dropwise, with constant stirring, until the pH is 10 (as determined by pH paper). If the sample contains solids, these must be removed by filtration (centrifugation is an acceptable alternative, subject to the approval of the Administrator), as follows: filter through Whatman No. 41 filter paper into a 100-ml volumetric flask; rinse the evaporating dish with three 5-ml portions of deionized, distilled water; filter these three rinses. Wash the filter with at least three 15-ml portions of deionized, distilled water. Add the filter washings to the contents of the volumetric flask and dilute to the mark with deionized, distilled water. If solids are absent, the solution can be transferred directly to the 100-ml volumetric flask and diluted to the mark with deionized, distilled water. Mix the contents of the flask thoroughly, and measure the absorbance at the optimum wavelength used for the standards (Section 5.2.1), using the blank solution as a zero reference. Dilute the sample and the blank with equal volumes of deionized, distilled water if the absorbance exceeds A_4, the absorbance of the 400 μg NO_2 standard (see Section 5.2.2). 87

5. *Calibration*

5.1 Flask Volume. The volume of the collection flask-flask valve combination must be known prior to sampling. Assemble the flask and flask valve and fill with water, to the stopcock. Measure the volume of water to ±10 ml. Record this volume on the flask.

5.2 Spectrophotometer Calibration.

5.2.1 **Optimum Wavelength Determination. Calibrate the wavelength scale of the spectrophotometer every 6 months. The calibration may be accomplished by using an energy source with an intense line emission such as a mercury lamp, or by using a series of glass filters spanning the measuring range of the spectrophotometer. Calibration materials are available commercially and from the National Bureau of Standards. Specific details on the use of such materials should be supplied by the vendor; general information about calibration techniques can be obtained from general reference books on analytical chemistry. The wavelength scale of the spectrophotometer must read correctly within ± 5 nm at all calibration points; otherwise, the spectrophotometer shall be repaired and recalibrated. Once the wavelength scale of the spectrophotometer is in proper calibration, use 410 nm as the optimum wavelength for the measurement of the absorbance of the standards and samples.** 87

Alternatively, a scanning procedure may be employed to determine the proper measuring wavelength. If the instrument is a double-beam spectrophotometer, scan the spectrum between 400 and 415 nm using a 200 μg NO_2 standard solution in the sample cell and a blank solution in the reference cell. If a peak does not occur, the spectrophotometer is probably malfunctioning and should be repaired. When a peak is obtained within the 400 to 415 nm range, the wavelength at which this peak occurs shall be the optimum wavelength for the measurement of absorbance of both the standards and the samples. For a single-beam spectrophotometer, follow the scanning procedure described above, except that the blank and standard solutions shall be scanned separately. The optimum wavelength shall be the wavelength at which the maximum difference in absorbance between the standard and the blank occurs. 87

5.2.2 **Determination of Spectrophotometer Calibration Factor K_c. Add 0.0 ml, 2 ml, 4 ml, 6 ml, and 8 ml of the KNO_3 working standard solution (1 ml=100 μg NO_2) to a series of five 50-ml volumetric flasks. To each flask, add 25 ml of absorbing solution, 10 ml deionized, distilled water, and sodium hydroxide (1 N) dropwise until the pH is between 9 and 12 (about 25 to 35 drops each). Dilute to the mark with deionized, distilled water. Mix thoroughly and pipette a 25-ml aliquot of each solution into a separate porcelain evaporating dish.** 87

Beginning with the evaporation step, follow the analysis procedure of Section 4.3, until the solution has been transferred to the 100 ml volumetric flask and diluted to the mark. Measure the absorbance of each solution, at the optimum wavelength, as determined in Section 5.2.1. This calibration procedure must be repeated on each day that samples are analysed. Calculate the spectrophotometer calibration factor as follows:

$$K_c=100\,\frac{A_1+2A_2+3A_3+4A_4}{A_1^2+A_2^2+A_3^2+A_4^2}$$

Equation 7-1

where:

K_c=Calibration factor

A_1=Absorbance of the 100-μg NO_2 standard

A_2=Absorbance of the 200-μg NO_2 standard

A_3=Absorbance of the 300-μg NO_2 standard

A_4=Absorbance of the 400-μg NO_2 standard

5.3 Barometer. Calibrate against a mercury barometer.

5.4 Temperature Gauge. Calibrate dial thermometers against mercury-in-glass thermometers.

5.5 Vacuum Gauge. Calibrate mechanical gauges, if used, against a mercury manometer such as that specified in 2.1.6.

5.6 Analytical Balance. Calibrate against standard weights.

6. *Calculations*

Carry out the calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculations.

6.1 Nomenclature.

A=Absorbance of sample.

C=Concentration of NO_x as NO_2, dry basis, corrected to standard conditions, mg/dscm (lb/dscf).

F=Dilution factor (i.e., 25/5, 25/10, etc., required only if sample dilution was needed to reduce the absorbance into the range of calibration).

K_c=Spectrophotometer calibration factor.

m=Mass of NO_x as NO_2 in gas sample, μg. 87

P_f=Final absolute pressure of flask, mm Hg (in. Hg).

P_i=Initial absolute pressure of flask, mm Hg (in. Hg).

P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

T_f=Final absolute temperature of flask, °K (°R).

T_i=Initial absolute temperature of flask, °K (°R).

T_{std}=Standard absolute temperature, 293° K (528° R)

V_{sc}=Sample volume at standard conditions (dry basis), ml.

V_f=Volume of flask and valve, ml.

V_a=Volume of absorbing solution, 25 ml.

2=50/25, the aliquot factor. (If other than a 25-ml aliquot was used for analysis, the corresponding factor must be substituted).

6.2 Sample volume, dry basis, corrected to standard conditions.

$$V_{sc}=\frac{T_{std}}{P_{std}}\,(V_f-V_a)\left[\frac{P_f}{T_f}-\frac{P_i}{T_i}\right]$$

$$=K_1(V_f-25\text{ ml})\left[\frac{P_f}{T_f}-\frac{P_i}{T_i}\right]$$

Equation 7-2

where:

$$K_1=0.3858\,\frac{°K}{\text{mm Hg}}\text{ for metric units}$$

$$=17.64\,\frac{°R}{\text{in. Hg}}\text{ for English units}$$

6.3 Total µg NO_2 per sample.

$$m = 2 K_c A F$$

Equation 7-3

NOTE.—If other than a 25-ml aliquot is used for analysis, the factor 2 must be replaced by a corresponding factor.

6.4 Sample concentration, dry basis, corrected to standard conditions.

$$C = K_2 \frac{m}{V_{sc}}$$

Equation 7-4

where:

$$K_2 = 10^3 \frac{\text{mg/m}^3}{\mu\text{g/ml}} \text{ for metric units}$$

$$= 6.243 \times 10^{-5} \frac{\text{lb/scf}}{\mu\text{g/ml}} \text{ for English units}$$

7. *Bibliography*

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METHOD 8—DETERMINATION OF SULFURIC ACID MIST AND SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted isokinetically from the stack. The sulfuric acid mist (including sulfur trioxide) and the sulfur dioxide are separated, and both fractions are measured separately by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfuric acid mist (including sulfur trioxide, and in the absence of other particulate matter) and sulfur dioxide emissions from stationary sources. Collaborative tests have shown that the minimum detectable limits of the method are 0.05 milligrams/cubic meter (0.03×10^{-7} pounds/cubic foot) for sulfur trioxide and 1.2 mg/m^3 (0.74×10^{-7} lb/ft^3) for sulfur dioxide. No upper limits have been established. Based on theoretical calculations for 200 milliliters of 3 percent hydrogen peroxide solution, the upper concentration limit for sulfur dioxide in a 1.0 m^3 (35.3 ft^3) gas sample is about 12,500 mg/m^3 (7.7×10^{-4} lb/ft^3). The upper limit can be extended by increasing the quantity of peroxide solution in the impingers.

Possible interfering agents of this method are fluorides, free ammonia, and dimethyl aniline. If any of these interfering agents are present (this can be determined by knowledge of the process), alternative methods, subject to the approval of the Administrator, U.S. EPA are required.[87]

Filterable particulate matter may be determined along with SO_3 and SO_2 (subject to the approval of the Administrator) by inserting a heated glass fiber filter between the probe and isopropanol impinger (see Section 2.1 of Method 6). If this option is chosen, particulate analysis is gravimetric only: H_2SO_4 acid mist is not determined separately.[87]

2. *Apparatus*

2.1 Sampling. A schematic of the sampling train used in this method is shown in Figure 8-1; it is similar to the Method 5 train except that the filter position is different and the filter holder does not have to be heated. Commercial models of this train are available. For those who desire to build their own, however, complete construction details are described in APTD-0581. Changes from the APTD-0581 document and allowable modifications to Figure 8-1 are discussed in the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD-0576. Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. Further details and guidelines on operation and maintenance are given in Method 5 and should be read and followed whenever they are applicable.

2.1.1 Probe Nozzle. Same as Method 5, Section 2.1.1.

2.1.2 Probe Liner. Borosilicate or quartz glass, with a heating system to prevent visible condensation during sampling. Do not use metal probe liners.

2.1.3 Pitot Tube. Same as Method 5, Section 2.1.3.

2.1.4 Differential Pressure Gauge. Same as Method 5, Section 2.1.4.

2.1.5 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other gasket materials, e.g., Teflon or Viton, may be used subject to the approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The filter holder shall be placed between the first and second impingers. Note: Do not heat the filter holder.

2.1.6 Impingers—Four, as shown in Figure 8-1. The first and third shall be of the Greenburg-Smith design with standard tips. The second and fourth shall be of the Greenburg-Smith design, modified by replacing the insert with an approximately 13 millimeter (0.5 in.) ID glass tube, having an unconstricted tip located 13 mm (0.5 in.) from the bottom of the flask. Similar collection systems, which have been approved by the Administrator, may be used.

2.1.7 Metering System. Same as Method 5, Section 2.1.8.

2.1.8 Barometer. Same as Method 5, Section 2.1.9.

2.1.9 Gas Density Determination Equipment. Same as Method 5, Section 2.1.10.

2.1.10 Temperature Gauge. Thermometer, or equivalent, to measure the temperature of the gas leaving the impinger train to within 1° C (2° F).

2.2 Sample Recovery.

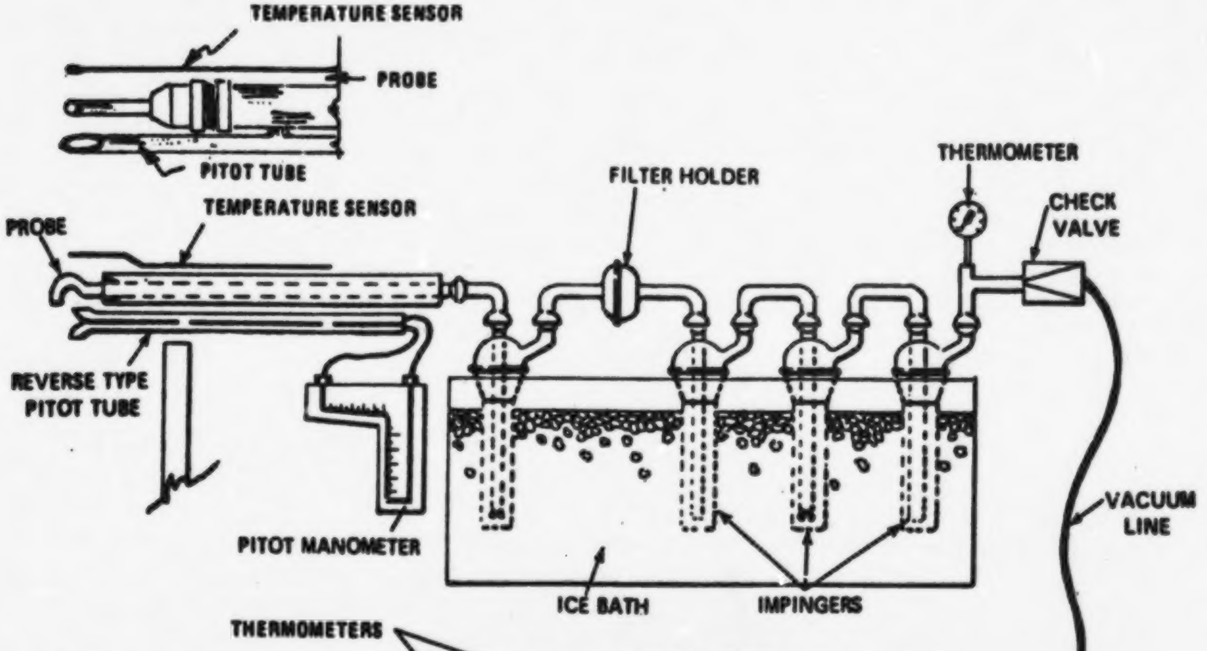

Figure 8-1. Sulfuric acid mist sampling train.

2.2.1 Wash Bottles. Polyethylene or glass, 500 ml (two).

2.2.2 Graduated Cylinders. 250 ml, 1 liter. (Volumetric flasks may also be used.)

2.2.3 Storage Bottles. Leak-free polyethylene bottles, 1000 ml size (two for each sampling run).

2.2.4 Trip Balance. 500-gram capacity, to measure to ±0.5 g (necessary only if a moisture content analysis is to be done).

2.3 Analysis.

2.3.1 Pipettes. Volumetric 25 ml, 100 ml.

2.3.2 Burette. 50 ml.

2.3.3 Erlenmeyer Flask. 250 ml. (one for each sample blank and standard).

2.3.4 Graduated Cylinder. 100 ml.

2.3.5 Trip Balance. 500 g capacity, to measure to ±0.5 g.

2.3.6 Dropping Bottle. To add indicator solution, 125-ml size.

3. *Reagents*

Unless otherwise indicated, all reagents are to conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available. Otherwise, use the best available grade.

3.1 Sampling.

3.1.1 Filters. Same as Method 5, Section 3.1.1.

3.1.2 Silica Gel. Same as Method 5, Section 3.1.2.

3.1.3 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.1.4 Isopropanol, 80 Percent. Mix 800 ml of isopropanol with 200 ml of deionized, distilled water.

NOTE.—Experience has shown that only A.C.S. grade isopropanol is satisfactory. Tests have shown that isopropanol obtained from commercial sources occasionally has peroxide impurities that will cause erroneously high sulfuric acid mist measurement. Use the following test for detecting peroxides in each lot of isopropanol: Shake 10 ml of the isopropanol with 10 ml of freshly prepared 10 percent potassium iodide solution. Prepare a blank by similarly treating 10 ml of distilled water. After 1 minute, read the absorbance on a spectrophotometer at 352 nanometers. If the absorbance exceeds 0.1, the isopropanol shall not be used. Peroxides may be removed from isopropanol by redistilling, or by passage through a column of activated alumina. However, reagent-grade isopropanol with suitably low peroxide levels is readily available from commercial sources; therefore, rejection of contaminated lots may be more efficient than following the peroxide removal procedure.

3.1.5 Hydrogen Peroxide, 3 Percent. Dilute 100 ml of 30 percent hydrogen peroxide to 1 liter with deionized, distilled water. Prepare fresh daily.

3.1.6 Crushed Ice.

3.2 Sample Recovery.

3.2.1 Water. Same as 3.1.3.

3.2.2 Isopropanol, 80 Percent. Same as 3.1.4.

3.3 Analysis.

3.3.1 Water. Same as 3.1.3.

3.3.2 Isopropanol, 100 Percent.

3.3.3 Thorin Indicator. 1-(o-arsonophenylazo)-2-naphthol-3, 6-disulfonic acid, disodium salt, or equivalent. Dissolve 0.20 g in 100 ml of deionized, distilled water.

3.3.4 Barium Perchlorate (0.0100 Normal). Dissolve 1.95 g of barium perchlorate trihydrate ($Ba(ClO_4)_2 \cdot 3H_2O$) in 200 ml deionized, distilled water, and dilute to 1 liter with isopropanol; 1.22 g of barium chloride dihydrate ($BaCl_2 \cdot 2H_2O$) may be used instead of the barium perchlorate. Standardize with sulfuric acid as in Section 5.2. This solution must be protected against evaporation at all times.

3.3.5 Sulfuric Acid Standard (0.0100 N). Purchase or standardize to ±0.0002 N against 0.0100 N NaOH that has previously been standardized against primary standard potassium acid phthalate.

4. *Procedure*

4.1 Sampling.

4.1.1 Pretest Preparation. Follow the procedure outlined in Method 5, Section 4.1.1; filters should be inspected, but need not be desiccated, weighed, or identified. If the effluent gas can be considered dry, i.e., moisture free, the silica gel need not be weighed.

4.1.2 Preliminary Determinations. Follow the procedure outlined in Method 5, Section 4.1.2.

4.1.3 Preparation of Collection Train. Follow the procedure outlined in Method 5, Section 4.1.3 (except for the second paragraph and other obviously inapplicable parts) and use Figure 8-1 instead of Figure 5-1. Replace the second paragraph with: Place 100 ml of 80 percent isopropanol in the first impinger, 100 ml of 3 percent hydrogen peroxide in both the second and third impingers; retain a portion of each reagent for use as a blank solution. Place about 200 g of silica gel in the fourth impinger.

PLANT ____________

LOCATION ____________

OPERATOR ____________

DATE ____________

RUN NO. ____________

SAMPLE BOX NO. ____________

METER BOX NO. ____________

METER ΔH@ ____________

C FACTOR ____________

PITOT TUBE COEFFICIENT, Cp ____________

SCHEMATIC OF STACK CROSS SECTION

STATIC PRESSURE, mm Hg (in. Hg) ____________

AMBIENT TEMPERATURE ____________

BAROMETRIC PRESSURE ____________

ASSUMED MOISTURE, % ____________

PROBE LENGTH, m (ft) ____________

NOZZLE IDENTIFICATION NO. ____________

AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) ____________

PROBE HEATER SETTING ____________

LEAK RATE, m^3/min, (cfm) ____________

PROBE LINER MATERIAL ____________

FILTER NO. ____________

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_S), °C (°F)	VELOCITY HEAD (ΔP_S), mm H_2O (in. H_2O)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER, mm H_2O (in. H_2O)	GAS SAMPLE VOLUME, m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET, °C (°F)	OUTLET, °C (°F)	
TOTAL							Avg	Avg	
AVERAGE							Avg		

Figure 8-2. Field data.

NOTE.—If moisture content is to be determined by impinger analysis, weigh each of the first three impingers (plus absorbing solution) to the nearest 0.5 g and record these weights. The weight of the silica gel (or silica gel plus container) must also be determined to the nearest 0.5 g and recorded.

4.1.4 Pretest Leak-Check Procedure. Follow the basic procedure outlined in Method 5, Section 4.1.4.1, noting that the probe heater shall be adjusted to the minimum temperature required to prevent condensation, and also that verbage such as, "· · · plugging the inlet to the filter holder · · ·," shall be replaced by, "· · · plugging the inlet to the first impinger · · ·." The pretest leak-check is optional. [87]

4.1.5 Train Operation. Follow the basic procedures outlined in Method 5, Section 4.1.5, in conjunction with the following special instructions. Data shall be recorded on a sheet similar to the one in Figure 8-2. The sampling rate shall not exceed 0.030 m³/min (1.0 cfm) during the run. Periodically during the test, observe the connecting line between the probe and first impinger for signs of condensation. If it does occur, adjust the probe heater setting upward to the minimum temperature required to prevent condensation. If component changes become necessary during a run, a leak-check shall be done immediately before each change, according to the procedure outlined in Section 4.1.4.2 of Method 5 (with appropriate modifications, as mentioned in Section 4.1.4 of this method); record all leak rates. If the leakage rate(s) exceed the specified rate, the tester shall either void the run or shall plan to correct the sample volume as outlined in Section 6.3 of Method 5. Immediately after component changes, leak-checks are optional. If these leak-checks are done, the procedure outlined in Section 4.1.4.1 of Method 5 (with appropriate modifications) shall be used.

After turning off the pump and recording the final readings at the conclusion of each run, remove the probe from the stack. Conduct a post-test (mandatory) leak-check as in Section 4.1.4.3 of Method 5 (with appropriate modification) and record the leak rate. If the post-test leakage rate exceeds the specified acceptable rate, the tester shall either correct the sample volume, as outlined in Section 6.3 of Method 5, or shall void the run.

Drain the ice bath and, with the probe disconnected, purge the remaining part of the train, by drawing clean ambient air through the system for 15 minutes at the average flow rate used for sampling.

NOTE.—Clean ambient air can be provided by passing air through a charcoal filter. At the option of the tester, ambient air (without cleaning) may be used.

4.1.6 Calculation of Percent Isokinetic. Follow the procedure outlined in Method 5, Section 4.1.6.

4.2 Sample Recovery.

4.2.1 Container No. 1. If a moisture content analysis is to be done, weigh the first impinger plus contents to the nearest 0.5 g and record this weight.

Transfer the contents of the first impinger to a 250-ml graduated cylinder. Rinse the probe, first impinger, all connecting glassware before the filter, and the front half of the filter holder with 80 percent isopropanol. Add the rinse solution to the cylinder. Dilute to 250 ml with 80 percent isopropanol. Add the filter to the solution, mix, and transfer to the storage container. Protect the solution against evaporation. Mark the level of liquid on the container and identify the sample container. [87]

4.2.2 Container No. 2. If a moisture content analysis is to be done, weigh the second and third impingers (plus contents) to the nearest 0.5 g and record these weights. Also, weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g.

Transfer the solutions from the second and third impingers to a 1000-ml graduated cylinder. Rinse all connecting glassware (including back half of filter holder) between the filter and silica gel impinger with deionized, distilled water, and add this rinse water to the cylinder. Dilute to a volume of 1000 ml with deionized, distilled water. Transfer the solution to a storage container. Mark the level of liquid on the container. Seal and identify the sample container.

4.3 Analysis.

Note the level of liquid in containers 1 and 2, and confirm whether or not any sample was lost during shipment; note this on the analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.

4.3.1 Container No. 1. Shake the container holding the isopropanol solution and the filter. If the filter breaks up, allow the fragments to settle for a few minutes before removing a sample. Pipette a 100-ml aliquot of this solution into a 250-ml Erlenmeyer flask, add 2 to 4 drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat the titration with a second aliquot of sample and average the titration values. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is greater.

4.3.2 Container No. 2. Thoroughly mix the solution in the container holding the contents of the second and third impingers. Pipette a 10-ml aliquot of sample into a 250-ml Erlenmeyer flask. Add 40 ml of isopropanol, 2 to 4 drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat the titration with a second aliquot of sample and average the titration values. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is greater. [87]

4.3.3 Blanks. Prepare blanks by adding 2 to 4 drops of thorin indicator to 100 ml of 80 percent isopropanol. Titrate the blanks in the same manner as the samples.

5. *Calibration*

5.1 Calibrate equipment using the procedures specified in the following sections of Method 5: Section 5.3 (metering system); Section 5.5 (temperature gauges); Section 5.7 (barometer). Note that the recommended leak-check of the metering system, described in Section 5.6 of Method 5, also applies to this method.

5.2 Standardize the barium perchlorate solution with 25 ml of standard sulfuric acid, to which 100 ml of 100 percent isopropanol has been added.

6. *Calculations*

Note.—Carry out calculations retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

6.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m² (ft²).
B_{ws} = Water vapor in the gas stream, proportion by volume.
$C_{H_2SO_4}$ = Sulfuric acid (including SO_3) concentration, g/dscm (lb/dscf). [87]
C_{SO_2} = Sulfur dioxide concentration, g/dscm (lb/dscf). [87]
I = Percent of isokinetic sampling.
N = Normality of barium perchlorate titrant, g equivalents/liter.
P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg). [87]
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg). [87]
T_m = Average absolute dry gas meter temperature (see Figure 8-2), ° K (° R).
T_s = Average absolute stack gas temperature (see Figure 8-2), ° K (° R).
T_{std} = Standard absolute temperature, 293° K (528° R). [87]
V_a = Volume of sample aliquot titrated, 100 ml for H_2SO_4 and 10 ml for SO_2.
V_{lc} = Total volume of liquid collected in impingers and silica gel, ml.
V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter corrected to standard conditions, dscm (dscf). [87]
v_s = Average stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 8, m/sec (ft/sec).
V_{soln} = Total volume of solution in which the sulfuric acid or sulfur dioxide sample is contained, 250 ml or 1,000 ml, respectively. [87]
V_t = Volume of barium perchlorate titrant used for the sample, ml.
V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.
Y = Dry gas meter calibration factor.
ΔH = Average pressure drop across orifice meter, mm (in.) H_2O.
θ = Total sampling time, min.
13.6 = Specific gravity of mercury.
60 = sec/min.
100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 8-2).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C and 760 mm Hg or 68° F and 29.92 in. Hg) by using Equation 8-1.

$$V_{m(std)}=V_mY\left(\frac{T_{std}}{T_m}\right)\frac{P_{bar}+\left(\frac{\Delta H}{13.6}\right)}{P_{std}}$$

$$=K_1V_mY\frac{P_{bar}+(\Delta H/13.6)}{T_m}$$

Equation 8-1

where:
K_1 = 0.3858 °K/mm Hg for metric units.
= 17.64 °R/in. Hg for English units.

NOTE.—If the leak rate observed during any mandatory leak-checks exceeds the specified acceptable rate, the tester shall either correct the value of V_m in Equation 8-1 (as described in Section 6.3 of Method 5), or shall invalidate the test run.

6.4 Volume of Water Vapor and Moisture Content. Calculate the volume of water vapor using Equation 5-2 of Method 5; the weight of water collected in the impingers and silica gel can be directly converted to milliliters (the specific gravity of water is 1 g/ml). Calculate the moisture content of the stack gas, using Equation 5-3 of Method 5. The "Note" in Section 6.5 of Method 5 also applies to this method. Note that if the effluent gas stream can be considered dry, the volume of water vapor and moisture content need not be calculated.

6.5 Sulfuric acid mist (including SO_3) concentration.

$$C_{H_2SO_4}=K_2\frac{N(V_t-V_{tb})\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 8-2

where:
K_2 = 0.04904 g/milliequivalent for metric units.
= 1.081×10^{-4} lb/meq for English units.

6.6 Sulfur dioxide concentration.

$$C_{SO_2}=K_3\frac{N(V_t-V_{tb})\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 8-3

where:
K_3 = 0.03203 g/meq for metric units.
= 7.061×10^{-5} lb/meq for English units.

6.7 Isokinetic Variation.

6.7.1 Calculation from raw data.

$$I=\frac{100\,T_s[K_4V_{lc}+(V_mY/T_m)\,P_{bar}+\Delta H/13.6)]}{60\,\theta V_sP_sA_n}$$

Equation 8-4[87]

where:
K_4 = 0.003464 mm Hg-m³/ml-°K for metric units.
= 0.002676 in. Hg-ft³/ml-°R for English units.

6.7.2 Calculation from intermediate values.

$$I=\frac{T_sV_{m(std)}P_{std}\,100}{T_{std}v_s\theta A_nP_s\,60\,(1-B_{ws})}$$

$$=K_5\frac{T_sV_{m(std)}}{P_sv_sA_n\theta(1-B_{ws})}$$

Equation 8-5

where:
K_5 = 4.320 for metric units.
= 0.09450 for English units.

6.8 Acceptable Results. If 90 percent ≤I ≤110 percent, the results are acceptable. If the results are low in comparison to the standards and I is beyond the acceptable range, the Administrator may opt to accept the results. Use Citation 4 in the Bibliography of Method 5 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography*

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METHOD 11—DETERMINATION OF HYDROGEN SULFIDE CONTENT OF FUEL GAS STREAMS IN PETROLEUM REFINERIES[79]

1. *Principle and applicability.* 1.1 *Principle.* Hydrogen sulfide (H_2S) is collected from a source in a series of midget impingers and absorbed in pH 3.0 cadmium sulfate ($CdSO_4$) solution to form cadmium sulfide (CdS). The latter compound is then measured iodometrically. An impinger containing hydrogen peroxide is included to remove SO_2 as an interfering species. This method is a revision of the H_2S method originally published in the FEDERAL REGISTER, Volume 39, No. 47, dated Friday, March 8, 1974.

1.2 *Applicability.* This method is applicable for the determination of the hydrogen sulfide content of fuel gas streams at petroleum refineries.

2. *Range and sensitivity.* The lower limit of detection is approximately 8 mg/m³ (6 ppm). The maximum of the range is 740 mg/m³ (520 ppm).

3. *Interferences.* Any compound that reduces iodine or oxidizes iodide ion will interfere in this procedure, provide it is collected in the cadmium sulfate impingers. Sulfur dioxide in concentrations of up to 2,600 mg/m³ is eliminated by the hydrogen peroxide solution. Thiols precipitate with hydrogen sulfide. In the absence of H_2S, only co-traces of thiols are collected. When methane- and ethane-thiols at a total level of 300 mg/m³ are present in addition to H_2S, the results vary from 2 percent low at an H_2S concentration of 400 mg/m³ to 14 percent high at an H_2S concentration of 100 mg/m³. Carbon oxysulfide at a concentration of 20 percent does not interfere. Certain carbonyl-containing compounds react with iodine and produce recurring end points. However, acetaldehyde and acetone at concentrations of 1 and 3 percent, respectively, do not interfere.

Entrained hydrogen peroxide produces a negative interference equivalent to 100 percent of that of an equimolar quantity of hydrogen sulfide. Avoid the ejection of hydrogen peroxide into the cadmium sulfate impingers.

4. *Precision and accuracy.* Collaborative testing has shown the within-laboratory coefficient of variation to be 2.2 percent and the overall coefficient of variation to be 5 percent. The method bias was shown to be —4.8 percent when only H_2S was present. In the presence of the interferences cited in section 3, the bias was positive at low H_2S concentrations and negative at higher concentrations. At 230 mg H_2S/m³, the level of the compliance standard, the bias was +2.7 percent. Thiols had no effect on the precision.

5. *Apparatus.*

5.1 Sampling apparatus.

5.1.1 Sampling line. Six to 7 mm (¼ in.) Teflon[1] tubing to connect the sampling train to the sampling valve.

5.1.2 Impingers. Five midget impingers, each with 30 ml capacity. The internal diameter of the impinger tip must be 1 mm ±0.05 mm. The impinger tip must be positioned 4 to 6 mm from the bottom of the impinger.

5.1.3 Glass or Teflon connecting tubing for the impingers.

5.1.4 Ice bath container. To maintain absorbing solution at a low temperature.

5.1.5 Drying tube. Tube packed with 6- to 16-mesh indicating-type silica gel, or equivalent, to dry the gas sample and protect the meter and pump. If the silica gel has been used previously, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to approval of the Administrator.

NOTE.—Do not use more than 30 g of silica gel. Silica gel absorbs gases such as propane from the fuel gas stream, and use of excessive amounts of silica gel could result in errors in the determination of sample volume.

5.1.6 Sampling valve. Needle valve or equivalent to adjust gas flow rate. Stainless steel or other corrosion-resistant material.

5.1.7 Volume meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate (~1.0 liter/min) and conditions actually encountered during sampling. The meter shall be equipped with a temperature gauge (dial thermometer or equivalent) capable of measuring temperature to within 3° C (5.4° F). The gas meter should have a petcock, or equivalent, on the outlet connector which can be closed during the leak check. Gas volume for one revolution of the meter must not be more than 10 liters.

5.1.8 Flow meter. Rotameter or equivalent, to measure flow rates in the range from 0.5 to 2 liters/min (1 to 4 cfh).

5.1.9 Graduated cylinder, 25 ml size.

5.1.10 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby National Weather Service station, in which case, the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice-versa for elevation decrease.

5.1.11 U-tube manometer. 0–30 cm water column. For leak check procedure.

5.1.12 Rubber squeeze bulb. To pressurize train for leak check.

5.1.13 Tee, pinchclamp, and connecting tubing. For leak check.

5.1.14 Pump. Diaphragm pump, or equivalent. Insert a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter. The pump is used for the air purge at the end of the sample run; the pump is not ordinarily used during sampling, because fuel gas streams are usually sufficiently pressurized to force sample gas through the train at the required flow rate. The pump need not be leak-free unless it is used for sampling.

5.1.15 Needle valve or critical orifice. To set air purge flow to 1 liter/min.

5.1.16 Tube packed with active carbon. To filter air during purge.

5.1.17 Volumetric flask. One 1,000 ml.

5.1.18 Volumetric pipette. One 15 ml.

5.1.19 Pressure-reduction regulator. Depending on the sampling stream pressure, a pressure-reduction regulator may be needed to reduce the pressure of the gas stream entering the Teflon sample line to a safe level.

5.1.20 Cold trap. If condensed water or amine is present in the sample stream, a corrosion-resistant cold trap shall be used immediately after the sample tap. The trap shall not be operated below 0° C (32° F) to avoid condensation of C_3 or C_4 hydrocarbons.

5.2 Sample recovery.

5.2.1 Sample container. Iodine flask, glass-stoppered: 500 ml size.

5.2.2 Pipette. 50 ml volumetric type.

5.2.3 Graduated cylinders. One each 25 and 250 ml.

5.2.4 Flasks. 125 ml, Erlenmeyer.

5.2.5 Wash bottle.

5.2.6 Volumetric flasks. Three 1,000 ml.

5.3 Analysis.

5.3.1 Flask. 500 ml glass-stoppered iodine flask.

5.3.2 Burette. 50 ml.

5.3.3 Flask. 125 ml, Erlenmeyer.

5.3.4 Pipettes, volumetric. One 25 ml; two each 50 and 100 ml.

5.3.5 Volumetric flasks. One 1,000 ml; two 500 ml.

5.3.6 Graduated cylinders. One each 10 and 100 ml.

6. *Reagents.* Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available. Otherwise, use best available grade.

6.1 Sampling.

6.1.1 Cadmium sulfate absorbing solution. Dissolve 41 g of $3CdSO_4 \cdot 8H_2O$ and 15 ml of 0.1 M sulfuric acid in a 1-liter volumetric flask that contains approximately ¾ liter of deionized distilled water. Dilute to volume with deionized water. Mix thoroughly. pH should be 3±0.1. Add 10 drops of Dow-Corning Antifoam B. Shake well before use. If Antifoam B is not used, the alternate acidified iodine extraction procedure (section 7.2.2) must be used.

6.1.2 Hydrogen peroxide, 3 percent. Dilute 30 percent hydrogen peroxide to 3 percent as needed. Prepare fresh daily.

6.1.3 Water. Deionized, distilled to conform to ASTM specifications D1193-72, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

6.2 Sample recovery.

6.2.1 Hydrochloric acid solution (HCl), 3M. Add 240 ml of concentrated HCl (specific gravity 1.19) to 500 ml of deionized, distilled water in a 1-liter volumetric flask. Dilute to 1 liter with deionized water. Mix thoroughly.

6.2.2 Iodine solution 0.1 N. Dissolve 24 g of potassium iodide (KI) in 30 ml of deionized, distilled water. Add 12.7 g of resublimed iodine (I_2) to the potassium iodide solution. Shake the mixture until the iodine is completely dissolved. If possible, let the solution stand overnight in the dark. Slowly dilute the solution to 1 liter with deionized, distilled water, with swirling. Filter the solution if it is cloudy. Store solution in a brown-glass reagent bottle.

6.2.3 Standard iodine solution, 0.01 N. Pipette 100.0 ml of the 0.1 N iodine solution into a 1-liter volumetric flask and dilute to volume with deionized, distilled water. Standardize daily as in section 8.1.1. This solution must be protected from light. Reagent bottles and flasks must be kept tightly stoppered.

6.3 Analysis.

6.3.1 Sodium thiosulfate solution, standard 0.1 N. Dissolve 24.8 g of sodium thiosulfate pentahydrate ($Na_2S_2O_3 \cdot 5H_2O$) or 15.8 g of anhydrous sodium thiosulfate ($Na_2S_2O_3$) in 1 liter of deionized, distilled water and add 0.01 g of anhydrous sodium carbonate (Na_2CO_3) and 0.4 ml of chloroform ($CHCl_3$) to stabilize. Mix thoroughly by shaking or by aerating with nitrogen for approximately 15 minutes and store in a glass-stoppered, reagent bottle. Standardize as in section 8.1.2.

6.3.2 Sodium thiosulfate solution, standard 0.01 N. Pipette 50.0 ml of the standard 0.1 N thiosulfate solution into a volumetric flask and dilute to 500 ml with distilled water.

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[1] Mention of trade names of specific products does not constitute endorsement by the Environmental Protection Agency.

NOTE.—A 0.01 N phenylarsine oxide solution may be prepared instead of 0.01 N thiosulfate (see section 6.3.3).

6.3.3 Phenylarsine oxide solution, standard 0.01 N. Dissolve 1.80 g of phenylarsine oxide (C_6H_5AsO) in 150 ml of 0.3 N sodium hydroxide. After settling, decant 140 ml of this solution into 800 ml of distilled water. Bring the solution to pH 6-7 with 6N hydrochloric acid and dilute to 1 liter. Standardize as in section 8.1.3.

6.3.4 Starch indicator solution. Suspend 10 g of soluble starch in 100 ml of deionized, distilled water and add 15 g of potassium hydroxide (KOH) pellets. Stir until dissolved, dilute with 900 ml of deionized distilled water and let stand for 1 hour. Neutralize the alkali with concentrated hydrochloric acid, using an indicator paper similar to Alkacid test ribbon, then add 2 ml of glacial acetic acid as a preservative.

NOTE.—Test starch indicator solution for decomposition by titrating, with 0.01 N iodine solution, 4 ml of starch solution in 200 ml of distilled water that contains 1 g potassium iodide. If more than 4 drops of the 0.01 N iodine solution are required to obtain the blue color, a fresh solution must be prepared.

7. *Procedure.*

7.1 Sampling.

7.1.1 Assemble the sampling train as shown in figure 11-1, connecting the five midget impingers in series. Place 15 ml of 3 percent hydrogen peroxide solution in the first impinger. Leave the second impinger empty. Place 15 ml of the cadmium sulfate absorbing solution in the third, fourth, and fifth impingers. Place the impinger assembly in an ice bath container and place crushed ice around the impingers. Add more ice during the run, if needed.

7.1.2 Connect the rubber bulb and manometer to first impinger, as shown in figure 11-1. Close the petcock on the dry gas meter outlet. Pressurize the train to 25-cm water pressure with the bulb and close off tubing connected to rubber bulb. The train must hold a 25-cm water pressure with not more than a 1-cm drop in pressure in a 1-minute interval. Stopcock grease is acceptable for sealing ground glass joints.

NOTE.—This leak check procedure is optional at the beginning of the sample run, but is mandatory at the conclusion. Note also that if the pump is used for sampling, it is recommended (but not required) that the pump be leak-checked separately, using a method consistent with the leak-check procedure for diaphragm pumps outlined in section 4.1.2 of reference method 6, 40 CFR Part 60, Appendix A.

7.1.3 Purge the connecting line between the sampling valve and first impinger, by disconnecting the line from the first impinger, opening the sampling valve, and allowing process gas to flow through the line for a minute or two. Then, close the sampling valve and reconnect the line to the impinger train. Open the petcock on the dry gas meter outlet. Record the initial dry gas meter reading.

7.1.4 Open the sampling valve and then adjust the valve to obtain a rate of approximately 1 liter/min. Maintain a constant (±10 percent) flow rate during the test. Record the meter temperature.

7.1.5 Sample for at least 10 min. At the end of the sampling time, close the sampling valve and record the final volume and temperature readings. Conduct a leak check as described in Section 7.1.2 above.

7.1.6 Disconnect the impinger train from the sampling line. Connect the charcoal tube and the pump, as shown in figure 11-1. Purge the train (at a rate of 1 liter/min) with clean ambient air for 15 minutes to ensure that all H_2S is removed from the hydrogen peroxide. For sample recovery, cap the open ends and remove the impinger train to a clean area that is away from sources of heat. The area should be well lighted, but not exposed to direct sunlight.

7.2 Sample recovery.

7.2.1 Discard the contents of the hydrogen peroxide impinger. Carefully rinse the contents of the third, fourth, and fifth impingers into a 500 ml iodine flask.

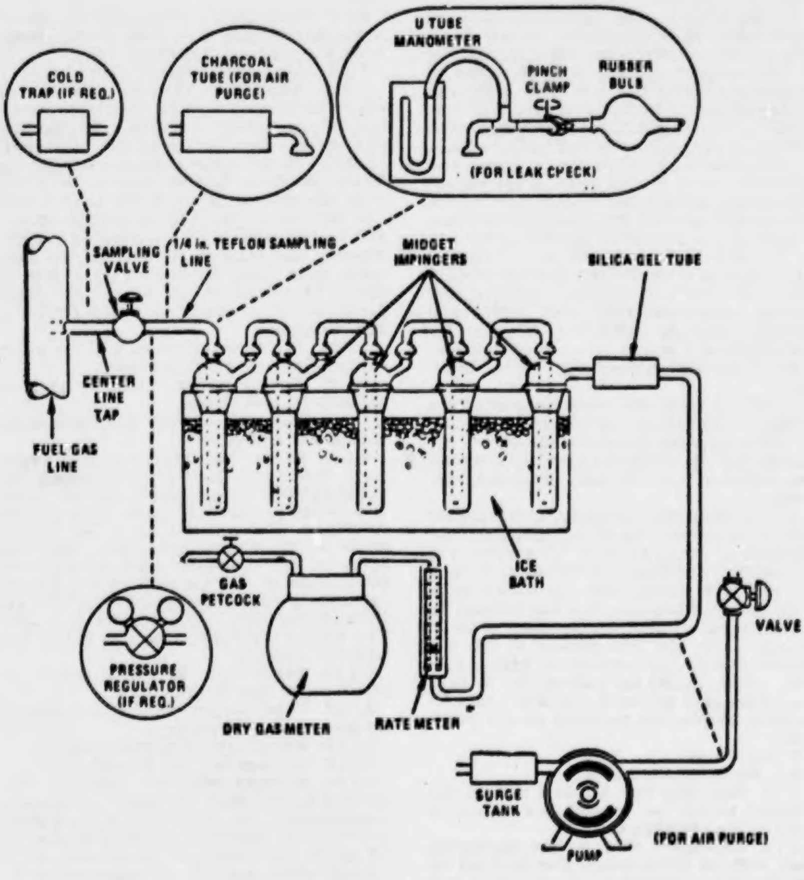

Figure 11-1. H_2S sampling train.

NOTE.—The impingers normally have only a thin film of cadmium sulfide remaining after a water rinse. If Antifoam B was not used or if significant quantities of yellow cadmium sulfide remain in the impingers, the alternate recovery procedure described below must be used.

7.2.2 Pipette exactly 50 ml of 0.01 N iodine solution into a 125 ml Erlenmeyer flask. Add 10 ml of 3 M HCl to the solution. Quantitatively rinse the acidified iodine into the iodine flask. Stopper the flask immediately and shake briefly.

7.2.2 (Alternate). Extract the remaining cadmium sulfide from the third, fourth, and fifth impingers using the acidified iodine solution. Immediately after pouring the acidified iodine into an impinger, stopper it and shake for a few moments, then transfer the liquid to the iodine flask. Do not transfer any rinse portion from one impinger to another; transfer it directly to the iodine flask. Once the acidified iodine solution has been poured into any glassware containing cadmium sulfide, the container must be tightly stoppered at all times except when adding more solution, and this must be done as quickly and carefully as possible. After adding any acidified iodine solution to the iodine flask, allow a few minutes for absorption of the H_2S before adding any further rinses. Repeat the iodine extraction until all cadmium sulfide is removed from the impingers. Extract that part of the connecting glassware that contains visible cadmium sulfide.

Quantitatively rinse all of the iodine from the impingers, connectors, and the beaker into the iodine flask using deionized, distilled water. Stopper the flask and shake briefly.

7.2.3 Allow the iodine flask to stand about 30 minutes in the dark for absorption of the H_2S into the iodine, then complete the titration analysis as in section 7.3.

NOTE.—Caution! Iodine evaporates from acidified iodine solutions. Samples to which acidified iodine have been added may not be stored, but must be analyzed in the time schedule stated in section 7.2.3.

7.2.4 Prepare a blank by adding 45 ml of cadmium sulfate absorbing solution to an iodine flask. Pipette exactly 50 ml of 0.01 N iodine solution into a 125-ml Erlenmeyer flask. Add 10 ml of 3 M HCl. Follow the same impinger extracting and quantitative rinsing procedure carried out in sample analysis. Stopper the flask, shake briefly, let stand 30 minutes in the dark, and titrate with the samples.

NOTE.—The blank must be handled by exactly the same procedure as that used for the samples.

7.3 Analysis.

NOTE.—Titration analyses should be conducted at the sample-cleanup area in order to prevent loss of iodine from the sample. Titration should never be made in direct sunlight.

7.3.1 Using 0.01 N sodium thiosulfate solution (or 0.01 N phenylarsine oxide, if applicable), rapidly titrate each sample in an iodine flask using gentle mixing, until solution is light yellow. Add 4 ml of starch indicator solution and continue titrating slowly until the blue color just disappears. Record V_{TT}, the volume of sodium thiosulfate solution used, or V_{AT}, the volume of phenylarsine oxide solution used (ml).

7.3.2 Titrate the blanks in the same manner as the samples. Run blanks each day until replicate values agree within 0.05 ml. Average the replicate titration values which agree within 0.05 ml.

8. *Calibration and standards.*

8.1 Standardizations.

8.1.1 Standardize the 0.01 N iodine solution daily as follows: Pipette 25 ml of the iodine solution into a 125 ml Erlenmeyer flask. Add 2 ml of 3 M HCl. Titrate rapidly with standard 0.01 N thiosulfate solution or with 0.01 N phenylarsine oxide until the solution is light yellow, using gentle mixing. Add four drops of starch indicator solution and continue titrating slowly until the blue color just disappears. Record V_T, the volume of thiosulfate solution used, or V_{AS}, the volume of phenylarsine oxide solution used (ml). Repeat until replicate values agree within 0.05 ml. Average the replicate titration values which agree within 0.05 ml and calculate the exact normality of the iodine solution using equation 9.3. Repeat the standardization daily.

8.1.2 Standardize the 0.1 N thiosulfate solution as follows: Oven-dry potassium dichromate ($K_2Cr_2O_7$) at 180 to 200° C (360 to 390° F). Weigh to the nearest milligram, 2 g of potassium dichromate. Transfer the dichromate to a 500 ml volumetric flask, dissolve in deionized, distilled water and dilute to exactly 500 ml. In a 500 ml iodine flask, dissolve approximately 3 g of potassium iodide (KI) in 45 ml of deionized, distilled water, then add 10 ml of 3 M hydrochloric acid solution. Pipette 50 ml of the dichromate solution into this mixture. Gently swirl the solution once and allow it to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of deionized distilled water, washing down the sides of the flask with part of the water. Titrate with 0.1 N thiosulfate until the solution is light yellow. Add 4 ml of starch indicator and continue titrating slowly to a green end point. Record V_s, the volume of thiosulfate solution used (ml). Repeat until replicate analyses agree within 0.05 ml. Calculate the normality using equation 9.1. Repeat the standardization each week, or after each test series, whichever time is shorter.

8.1.3 Standardize the 0.01 N Phenylarsine oxide (if applicable) as follows: oven dry potassium dichromate ($K_2Cr_2O_7$) at 180 to 200° C (360 to 390° F). Weigh to the nearest milligram, 2 g of the $K_2Cr_2O_7$; transfer the dichromate to a 500 ml volumetric flask, dissolve in deionized, distilled water, and dilute to exactly 500 ml. In a 500 ml iodine flask, dissolve approximately 0.3 g of potassium iodide (KI) in 45 ml of deionized, distilled water; add 10 ml of 3M hydrochloric acid. Pipette 5 ml of the $K_2Cr_2O_7$ solution into the iodine flask. Gently swirl the contents of the flask once and allow to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of deionized, distilled water, washing down the sides of the flask with part of the water. Titrate with 0.01 N phenylarsine oxide until the solution is light yellow. Add 4 ml of starch indicator and continue titrating slowly to a green end point. Record V_A, the volume of phenylarsine oxide used (ml). Repeat until replicate analyses agree within 0.05 ml. Calculate the normality using equation 9.2. Repeat the standardization each week or after each test series, whichever time is shorter.

8.2 Sampling train calibration. Calibrate the sampling train components as follows:

8.2.1 Dry gas meter.

8.2.1.1 Initial calibration. The dry gas meter shall be calibrated before its initial use in the field. Proceed as follows: First, assemble the following components in series: Drying tube, needle valve, pump, rotameter, and dry gas meter. Then, leak-check the system as follows: Place a vacuum gauge (at least 760 mm Hg) at the inlet to the drying tube and pull a vacuum of 250 mm (10 in.) Hg; plug or pinch off the outlet of the flow meter, and then turn off the pump. The vacuum shall remain stable for at least 30 seconds. Carefully release the vacuum gauge before releasing the flow meter end.

Next, calibrate the dry gas meter (at the sampling flow rate specified by the method) as follows: Connect an appropriately sized wet test meter (e.g., 1 liter per revolution) to the inlet of the drying tube. Make three independent calibration runs, using at least five revolutions of the dry gas meter per run. Calculate the calibration factor, *Y* (wet test meter calibration volume divided by the dry gas meter volume, both volumes adjusted to the same reference temperature and pressure), for each run, and average the results. If any *Y* value deviates by more than 2 percent from the average, the dry gas meter is unacceptable for use. Otherwise, use the average as the calibration factor for subsequent test runs.

8.2.1.2 Post-test calibration check. After each field test series, conduct a calibration check as in section 8.2.1.1. above, except for the following variations: (a) The leak check is not to be conducted, (b) three or more revolutions of the dry gas meter may be used, and (2) only two independent runs need be made. If the calibration factor does not deviate by more than 5 percent from the initial calibration factor (determined in section 8.2.1.1.), then the dry gas meter volumes obtained during the test series are acceptable. If the calibration factor deviates by more than 5 percent, recalibrate the dry gas meter as in section 8.2.1.1, and for the calculations, use the calibration factor (initial or recalibration) that yields the lower gas volume for each test run.

8.2.2 Thermometers. Calibrate against mercury-in-glass thermometers.

8.2.3 Rotameter. The rotameter need not be calibrated, but should be cleaned and maintained according to the manufacturer's instruction.

8.2.4 Barometer. Calibrate against a mercury barometer.

9. *Calculations.* Carry out calculations retaining at least one extra decimal figure beyond that of the acquired data. Round off results only after the final calculation.

9.1 Normality of the Standard (~0.1 N) Thiosulfate Solution.

$$N_s = 2.039 W/V_s$$

where:

W = Weight of $K_2Cr_2O_7$ used, g.
V_s = Volume of $Na_2S_2O_3$ solution used, ml.
N_s = Normality of standard thiosulfate solution, g-eq/liter.
2.039 = Conversion factor

(6 eq. I_2/mole $K_2Cr_2O_7$) (1,000 ml/liter)/= (294.2 g $K_2Cr_2O_7$/mole) (10 aliquot factor)

9.2 Normality of Standard Phenylarsine Oxide Solution (if applicable).

$$N_A = 0.2039 W/V_A$$

where:

W = Weight of $K_2Cr_2O_7$ used, g.
V_A = Volume of C_6H_5AsO used, ml.
N_A = Normality of standard phenylarsine oxide solution, g-eq/liter.
0.2039 = Conversion factor

(6 eq. I_2/mole $K_2Cr_2O_7$) (1,000 ml/liter)/ (249.2 g $K_2Cr_2O_7$/mole) (100 aliquot factor)

9.3 Normality of Standard Iodine Solution.

$$N_I = N_T V_T / V_I$$

where:

N_I = Normality of standard iodine solution, g-eq/liter.
V_I = Volume of standard iodine solution used, ml.
N_T = Normality of standard (~0.01 N) thiosulfate solution; assumed to be 0.1 N_A, g-eq/liter.
V_T = Volume of thiosulfate solution used, ml.

NOTE.—If phenylarsine oxide is used intead of thiosulfate, replace N_T and V_T in Equation 9.3 with N_A and V_{AS}, respectively (see sections 8.1.1 and 8.1.3).

9.4 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C) and 760 mm Hg.

$$V_{m(std)} = V_m Y \left[(T_{std}/T_m)(P_{bar}/P_{std})\right]$$

where:

$V_{m(std)}$ = Volume at standard conditions of gas sample through the dry gas meter, standard liters.
V_m = Volume of gas sample through the dry gas meter (meter conditions), liters.
T_{std} = Absolute temperature at standard conditions, 293° K.
T_m = Average dry gas meter temperature, °K.
P_{bar} = Barometric pressure at the sampling site, mm Hg.
P_{std} = Absolute pressure at standard conditions, 760 mm Hg.
Y = Dry gas meter calibration factor.

9.5 Concentration of H_2S. Calculate the concentration of H_2S in the gas stream at standard conditions using the following equation:

$$C_{H_2S} = K[(V_{IT}N_I - V_{TT}N_T)\text{ sample} - (V_{IT}N_I - V_{TT}N_T)\text{ blank}]/V_{m(std)}$$

where (metric units):

C_{H_2S} = Concentration of H_2S at standard conditions, mg/dscm.
K = Conversion factor = 17.04×10^3

(34.07 g/mole H_2S) (1,000 liters/m^3) (1,000 mg/g)/ = (1,000 ml/liter) ($2H_2S$ eq/mole)

V_{IT} = Volume of standard iodine solution = 50.0 ml.
N_I = Normality of standard iodine solution, g-eq/liter.
V_{TT} = Volume of standard (~0.01 N) sodium thiosulfate solution, ml.
N_T = Normality of standard sodium thiosulfate solution, g-eq/liter.
$V_{m(std)}$ = Dry gas volume at standard conditions, liters.

NOTE.—If phenylarsine oxide is used instead of thiosulfate, replace N_T and V_{TT} in Equation 9.5 with N_A and V_{AT}, respectively (see Sections 7.3.1 and 8.1.3).

10. *Stability*. The absorbing solution is stabie for at least 1 month. Sample recovery and analysis should begin within 1 hour of sampling to minimize oxidation of the acidified cadmium sulfide. Once iodine has been added to the sample, the remainder of the analysis procedure must be completed according to sections 7.2.2 through 7.3.2.

11. *Bibliography*.

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11.2 Tentative Method of Determination of Hydrogen Sulfide and Mercaptan Sulfur in Natural Gas, Natural Gas Processors Association, Tulsa, Okla., NGPA Publication No. 2265-65, 1965.

11.3 Knoll, J. E., and M. R. Midgett. Determination of Hydrogen Sulfide in Refinery Fuel Gases, Environmental Monitoring Series, Office of Research and Development, USEPA, Research Triangle Park, N.C. 27711, EPA 600/4-77-007.

11.4 Scheill, G. W., and M. C. Sharp. Standardization of Method 11 at a Petroleum Refinery, Midwest Research Institute Draft Report for USEPA, Office of Research and Development, Research Triangle Park, N.C. 27711, EPA Contract No. 68-02-1098, August 1976, EPA 600/4-77-088a (Volume 1) and EPA 600/4-77-088b (Volume 2).

(Secs. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

METHOD 13—DETERMINATION OF TOTAL FLUORIDE EMISSIONS FROM STATIONARY SOURCES—SPADNS ZIRCONIUM LAKE METHOD [14]

1. *Principle and Applicability.*

1.1 *Principle.* Gaseous and particulate fluorides are withdrawn isokinetically from the source using a sampling train. The fluorides are collected in the impinger water and on the filter of the sampling train. The weight of total fluorides in the train is determined by the SPADNS Zirconium Lake colorimetric method.

1.2 *Applicability.* This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards. Fluorocarbons, such as Freons, are not quantitatively collected or measured by this procedure.

2. *Range and Sensitivity.*

The SPADNS Zirconium Lake analytical method covers the range from 0–1.4 μg/ml fluoride. Sensitivity has not been determined.

3. *Interferences.*

During the laboratory analysis, aluminum in excess of 300 mg/liter and silicon dioxide in excess of 300 μg/liter will prevent complete recovery of fluoride. Chloride will distill over and interfere with the SPADNS Zirconium Lake color reaction. If chloride ion is present, use of Specific Ion Electrode (Method 13B) is recommended; otherwise a chloride determination is required and 5 mg of silver sulfate (see section 7.3.6) must be added for each mg of chloride to prevent chloride interference. If sulfuric acid is carried over in the distillation, it will cause a positive interference. To avoid sulfuric acid carryover, it is important to stop distillation at 175°C.

4. *Precision, Accuracy and Stability.*

4.1 *Analysis.* A relative standard deviation of 3 percent was obtained from twenty replicate intralaboratory determinations on stack emission samples with a concentration range of 39 to 360 mg/l. A phosphate rock standard which was analyzed by this procedure contained a certified value of 3.84 percent. The average of five determinations was 3.86 percent fluoride.

4.2 *Stability.* The color obtained when the sample and colorimetric reagent are mixed is stable for approximately two hours. After formation of the color, the absorbances of the sample and standard solutions should be measured at the same temperature. A 3°C temperature difference between sample and standard solutinos will produce an error of approximately 0.005 mg F/liter.

5. *Apparatus.*

5.1 *Sample train.* See Figure 13A–1; it is similar to the Method 5 train except for the interchangeability of the position of the filter. Commercial models of this train are available. However, if one desires to build his own, complete construction details are described in APTD–0581; for changes from the APTD–0581 document and for allowable modifications to Figure 13A–1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD–0576. Since correct usage is important in obtaining valid results, all users should read the APTD–0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein.

5.1.1 Probe nozzle—Stainless steel (316) with sharp, tapered leading edge. The angle of taper shall be ≦30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. The wall thickness of the nozzle shall be less than or equal to that of 20 gauge tubing, i.e., 0.165 cm (0.065 in.) and the distance from the tip of the nozzle to the first bend or point of disturbance shall be at least two times the outside nozzle diameter. The nozzle shall be constructed from seamless stainless steel tubing. Other configurations and construction material may be used with approval from the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 cm (⅛ in.) up to 1.27 cm (½ in.) (or larger if higher volume sampling trains are used) inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in the calibration section.

5.1.2 Probe liner—Borosilicate glass or stainless steel (316). When the filter is located immediately after the probe, a probe heating system may be used to prevent filter plugging resulting from moisture condensation. The temperature in the probe shall not exceed 120 ± 14°C (248 ± 25°F).

5.1.3 Pitot tube—Type S, or other device approved by the Administrator, attached to probe to allow constant monitoring of the stack gas velocity. The face openings of the pitot tube and the probe nozzle shall be adjacent and parallel to each other, not necessarily on the same plane, during sampling. The free space between the nozzle and pitot tube shall be at least 1.9 cm (0.75 in.). The free space shall be set based on a 1.3 cm (0.5 in.) ID nozzle, which is the largest size nozzle used.

The pitot tube must also meet the criteria specified in Method 2 and be calibrated according to the procedure in the calibration section of that method.

5.1.4 Differential pressure gauge—Inclined manometer capable of measuring velocity head to within 10% of the minimum measured value. Below a differential pressure of 1.3 mm (0.05 in.) water gauge, micromanometers with sensitivities of 0.013 mm (0.0005 in.) should be used. However, micromanometers are not easily adaptable to field conditions and are not easy to use with pulsating flow. Thus, other methods or devices acceptable to the Administrator may be used when conditions warrant.

5.1.5 Filter holder—If located between the probe and first impinger, borosilicate glass with a 20 mesh stainless steel screen filter support and a silicone rubber gasket; neither a glass frit filter support nor a sintered metal filter support may be used if the filter is in front of the impingers. If located between the third and fourth impingers, borosilicate glass with a glass frit filter support and a silicone rubber gasket. Other materials of construction may be used with approval from the Administrator, e.g., if probe liner is stainless steel, then filter holder may be stainless steel. The holder design shall provide a positive seal against leakage from the outside or around the filter.[50]

5.1.6 Filter heating system—When moisture condensation is a problem, any heating system capable of maintaining a temperature around the filter holder during sampling of no greater than 120±14°C (248±25°F). A temperature gauge capable of measuring temperature to within 3°C (5.4°F) shall be installed so that when the filter heater is used, the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD–0581 may be used.

5.1.7 Impingers—Four impingers connected as shown in Figure 13A–1 with ground glass (or equivalent), vacuum tight fittings. The first, third, and fourth impingers are of the Greenburg-Smith design, modified by replacing the tip with a 1¼ cm (½ in.) inside diameter glass tube extending to 1¼ cm (½ in.) from the bottom of the flask. The second impinger is of the Greensburg-Smith design with the standard tip.

5.1.8 Metering system—Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3°C (~5°F), dry gas meter with 2% accuracy at the required sampling rate, and related equipment, or equivalent, as required to maintain an isokinetic sampling rate and to determine sample volume. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

5.1.9 Barometer—Mercury, aneroid, or other barometers capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby weather bureau station, in which case the station value shall be requested and an adjustment for elevation differences shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase.

5.2 *Sample recovery.*

5.2.1 Probe liner and probe nozzle brushes—Nylon bristles with stainless steel wire handles. The probe brush shall have extensions, at least as long as the probe, of stainless steel, teflon, or similarly inert material. Both brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

5.2.2 Glass wash bottles—Two.

5.2.3 Sample storage containers—Wide mouth, high density polyethylene bottles, 1 liter.

5.2.4 Plastic storage containers—Air tight containers of sufficient volume to store silica gel.

5.2.5 Graduated cylinder—250 ml.

5.2.6 Funnel and rubber policeman—to aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

5.3 *Analysis.*

5.3.1 Distillation apparatus—Glass distillation apparatus assembled as shown in Figure 13A–2.

5.3.2 Hot plate—Capable of heating to 500° C.

5.3.3 Electric muffle furnace—Capable of heating to 600° C.

5.3.4 Crucibles—Nickel, 75 to 100 ml capacity.

5.3.5 Beaker, 1500 ml.

5.3.6 Volumetric flask—50 ml.

5.3.7 Erlenmeyer flask or plastic bottle—500 ml.

5.3.8 Constant temperature bath—Capable of maintaining a constant temperature of ±1.0° C in the range of room temperature.

5.3.9 Balance—300 g capacity to measure to ±0.5 g.

5.3.10 Spectrophotometer — Instrument capable of measuring absorbance at 570 nm and providing at least a 1 cm light path.

5.3.11 Spectrophotometer cells—1 cm.

6. *Reagents*

6.1 *Sampling.*

6.1.1 Filters—Whatman No. 1 filters, or equivalent, sized to fit filter holder.

6.1.2 Silica gel—Indicating type, 6–16 mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received.

6.1.3 Water—Distilled.

6.1.4 Crushed ice.

6.1.5 Stopcock grease—Acetone insoluble, heat stable silicone grease. This is not necessary if screw-on connectors with teflon sleeves, or similar, are used.

6.2 *Sample recovery.*

6.2.1 Water—Distilled from same container as 6.1.3.

6.3 *Analysis.*

6.3.1 Calcium oxide (CaO)—Certified grade containing 0.005 percent fluoride or less.

6.3.2 Phenolphthalein Indicator—0.1 percent in 1:1 ethanol-water mixture.

6.3.3 Silver sulfate (Ag_2SO_4)—ACS reagent grade, or equivalent.

6.3.4 Sodium hydroxide (NaOH)—Pellets, ACS reagent grade, or equivalent.

6.3.5 Sulfuric acid (H_2SO_4)—Concentrated, ACS reagent grade, or equivalent.

6.3.6 Filters—Whatman No. 541, or equivalent.

6.3.7 Hydrochloric acid (HCl)—Concentrated, ACS reagent grade, or equivalent.

6.3.8 Water—Distilled, from same container as 6.1.2.

6.3.9 Sodium fluoride—Standard solution. Dissolve 0.2210 g of sodium fluoride in 1 liter of distilled water. Dilute 100 ml of this solution to 1 liter with distilled water. One milliliter of the solution contains 0.01 mg of fluoride.

6.3.10 SPADNS solution—[4,5dihydroxy-3-(p-sulfophenylazo)-2,7-naphthalene - disulfonic acid trisodium salt]. Dissolve 0.960 ±.010 g of SPADNS reagent in 500 ml distilled water. This solution is stable for at least one month, if stored in a well-sealed bottle protected from sunlight.

6.3.11 Reference solution—Add 10 ml of SPADNS solution (6.3.10) to 100 ml distilled water and acidify with a solution prepared by diluting 7 ml of concentrated HCl to 10 ml with distilled water. This solution is used to set the spectrophotometer zero point and should be prepared daily.

6.3.12 SPADNS Mixed Reagent—Dissolve 0.135 ±0.005 g of zirconyl chloride octahydrate ($ZrOCl_2 \cdot 8H_2O$), in 25 ml distilled water. Add 350 ml of concentrated HCl and dilute to 500 ml with distilled water. Mix equal volumes of this solution and SPADNS solution to form a single reagent. This reagent is stable for at least two months.

7. *Procedure.*

NOTE: The fusion and distillation steps of this procedure will not be required, if it can be shown to the satisfaction of the Administrator that the samples contain only water-soluble fluorides.

7.1 *Sampling.* The sampling shall be conducted by competent personnel experienced with this test procedure.

7.1.1 Pretest preparation. All train components shall be maintained and calibrated according to the procedure described in APTD–0576, unless otherwise specified herein.

Weigh approximately 200–300 g of silica gel in air tight containers to the nearest 0.5 g. Record the total weight, both silica gel and container, on the container. More silica gel may be used but care should be taken during sampling that it is not entrained and carried out from the impinger. As an alternative, the silica gel may be weighed directly in the impinger or its sampling holder just prior to the train assembly.

7.1.2 Preliminary determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2 and moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate calculations. Estimates may be used. However, final results will be based on actual measurements made during the test.

Select a nozzle size based on the range of velocity heads such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the differential pressure gauge is capable of measuring the minimum velocity head value to within 10%, or as specified by the Administrator.

Select a suitable probe liner and probe length such that all traverse points can be sampled. Consider sampling from opposite sides for large stacks to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that the sampling time per point is not less than 2 min. or select some greater time interval as specified by the Administrator, and such that the sample volume that will be taken will exceed the required minimum total gas sample volume specified in the test procedures for the specific industry. The latter is based on an approximate average sampling rate. Note also that the minimum total sample volume is corrected to standard conditions.

It is recommended that a half-integral or integral number of minutes be sampled at each point in order to avoid timekeeping errors.

In some circumstances, e.g. batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

7.1.3 Preparation of collection train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and place approximately 200–300 g or more, if necessary, of preweighed silica gel in the fourth impinger. Record the weight of the silica gel and container on the data sheet. Place the empty container in a clean place for later use in the sample recovery.

Place a filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as to not allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed.

When glass liners are used, install selected nozzle using a Viton A O-ring; the Viton A O-ring is installed as a seal where the nozzle is connected to a glass liner. See APTD–0576 for details. When metal liners are used, install the nozzle as above or by a leak free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Unless otherwise specified by the Administrator, attach a temperature probe to the metal sheath of the sampling probe so that the sensor extends beyond the probe tip and does not touch any metal. Its position should be about 1.9 to 2.54 cm (0.75 to 1 in.) from the pitot tube and probe nozzle to avoid interference with the gas flow.

Assemble the train as shown in Figure 13A–1 with the filter between the third and fourth impingers. Alternatively, the filter may be placed between the probe and first impinger if a 20 mesh stainless steel screen is used for the filter support. A filter heating system may be used to prevent moisture condensation, but the temperature around the filter holder shall not exceed 120±14°C (248±25°F). [(Note: Whatman No. 1 filter decomposes at 150°C (300°F)).] Record filter location on the data sheet.[50]

Place crushed ice around the impingers.

7.14 Leak check procedure—After the sampling train has been assembled, turn on and set (if applicable) the probe and filter heating system(s) to reach a temperature sufficient to avoid condensation in the probe. Allow time for the temperature to stabilize. Leak check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum. A leakage rate in excess of 4% of the average sampling rate or 0.00057 m³/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak check instructions for the sampling train described in APTD–0576 and APTD–0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until 380 mm Hg (15 in. Hg) vacuum is reached. *Do not* reverse direction of by-pass valve. This will cause water to back up into the filter holder. If 380 mm Hg (15 in. Hg) is exceeded, either leak check at this higher vacuum or end the leak check as described below and start over.

When the leak check is completed, first slowly remove the plug from the inlet to the probe or filter holder and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder (if placed before the impingers) and silica gel from being entrained backward into the third impinger.

Leak checks shall be conducted as described whenever the train is disengaged, e.g. for silica gel or filter changes during the test, prior to each test run, and at the completion of each test run. If leaks are found to be in excess of the acceptable rate, the test will be considered invalid. To reduce lost time due to leakage occurrences, it is recommended that leak checks be conducted between port changes.

7.1.5 Particulate train operation—During the sampling run, an isokinetic sampling rate within 10%, or as specified by the Administrator, of true isokinetic shall be maintained.

For each run, record the data required on the example data sheet shown in Figure 13A–3. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, and when sampling is halted. Take other data point readings at least once at each sample point during each time increment and additional readings when significant changes (20% variation in velocity head readings) necessitate additional adjustments in flow rate. Be sure to level and zero the manometer.

Clean the portholes prior to the test run to minimize chance of sampling deposited material. To begin sampling, remove the nozzle cap, verify (if applicable) that the probe heater is working and filter heater is up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available for sampling trains using type S pitot tubes with 0.85±0.02 coefficients (C_p), and when sampling in air or a stack gas with equivalent density (molecular weight, M_d, equal to 29±4), which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. APTD–0576 details the procedure for using these nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomograph unless appropirate steps are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to avoid water backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes to minimize chance of extracting deposited material.

During the test run, make periodic adjustments to keep the probe and (if applicable) filter temperatures at their proper values. Add more ice and, if necessary, salt to the ice bath, to maintain a temperature of less than 20°C (68°F) at the impinger/silica gel outlet, to avoid excessive moisture losses. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes high enough to make isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. After the new filter or filter assembly is installed conduct a leak check. The final emission results shall be based on the summation of all filter catches.

A single train shall be used for the entire sample run, except for filter and silica gel changes. However, if approved by the Administrator, two or more trains may be used for a single test run when there are two or more ducts or sampling ports. The final emission results shall be based on the total of all sampling train catches.

At the end of the sample run, turn off the pump, remove the probe and nozzle from the stack, and record the final dry gas meter reading. Perform a leak check.[1] Calculate percent isokinetic (see calculation section) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the *Administrator* for possible variance on the isokinetic rates.

7.2 Sample recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to keep from losing part of the sample. Do not cap off the probe tip tightly while the sampling train is cooling down, as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate, if present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Ground glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Inspect the train prior to and during disassembly and note any abnormal conditions. Using a graduated cylinder, measure and record the volume of the water in the first three impingers, to the nearest ml; any condensate in the probe should be included in this determination. Treat the samples as follows:

7.2.1 Container No. 1. Transfer the impinger water from the graduated cylinder to this container. Add the filter to this container. Wash all sample exposed surfaces, including the probe tip, probe, first three impingers, impinger connectors, filter holder, and graduated cylinder thoroughly with distilled water. Wash each component three separate times with water and clean the probe and nozzle with brushes. A maximum wash of 500 ml is used, and the washings are added to the sample container which must be made of polyethylene.

7.2.2 Container No. 2. Transfer the silica gel from the fourth impinger to this container and seal.

7.3 *Analysis*. Treat the contents of each sample container as described below.

7.3.1 Container No. 1.

7.3.1.1 Filter this container's contents, including the Whatman No. 1 filter, through Whatman No. 541 filter paper, or equivalent into a 1500 ml beaker. Note: If filtrate volume exceeds 900 ml make filtrate basic with NaOH to phenolphthalein and evaporate to less than 900 ml.

7.3.1.2 Place the Whatman No. 541 filter containing the insoluble matter (including the Whatman No. 1 filter) in a nickel crucible, add a few ml of water and macerate the filter with a glass rod.

Add 100 mg CaO to the crucible and mix the contents thoroughly to form a slurry. Add a couple of drops of phenolphthalein indicator. The indicator will turn red in a basic medium. The slurry should remain basic during the evaporation of the water or fluoride ion will be lost. If the indicator turns colorless during the evaporation, an acidic condition is indicated. If this happens add CaO until the color turns red again.

Place the crucible in a hood under infrared lamps or on a hot plate at low heat. Evaporate the water completely.

After evaporation of the water, place the crucible on a hot plate under a hood and slowly increase the temperature until the paper chars. It may take several hours for complete charring of the filter to occur.

Place the crucible in a cold muffle furnace and gradually (to prevent smoking) increase the temperature to 600°C, and maintain until the contents are reduced to an ash. Remove the crucible from the furnace and allow it to cool.

7.3.1.3 Add approximately 4 g of crushed NaOH to the crucible and mix. Return the crucible to the muffle furnace, and fuse the sample for 10 minutes at 600°C.

Remove the sample from the furnace and cool to ambient temperature. Using several rinsings of warm distilled water transfer the contents of the crucible to the beaker containing the filtrate from container No. 1 (7.3.1). To assure complete sample removal, rinse finally with two 20 ml portions of 25 percent (v/v) sulfuric acid and carefully add to the beaker. Mix well and transfer a one-liter volumetric flask. Dilute to volume with distilled water and mix thoroughly. Allow any undissolved solids to settle.

7.3.2 Container No. 2. Weigh the spent silica gel and report to the nearest 0.5 g.

7.3.3 Adjustment of acid/water ratio in distillation flask—(Utilize a protective shield when carrying out this procedure.) Place 400 ml of distilled water in the distilling flask and add 200 ml of concentrated H_2SO_4. Caution: Observe standard precautions when mixing the H_2SO_4 by slowly adding the acid to the flask with constant swirling. Add some soft glass beads and several small pieces of broken glass tubing and assemble the apparatus as shown in Figure 13A-2. Heat the flask until it reaches a temperature of 175°C to adjust the acid/water ratio for subsequent distillations. Discard the distillate.

7.3.4 Distillation—Cool the contents of the distillation flask to below 80°C. Pipette an aliquot of sample containing less than 0.6 mg F directly into the distilling flask and add distilled water to make a total volume of 220 ml added to the distilling flask. [For an estimate of what size aliquot does not exceed 0.6 mg F, select an aliquot of the solution and treat as described in Section 7.3.5. This will give an approximation of the fluoride content, but only an approximation since interfering ions have not been removed by the distillation step.] 50

Place a 250 ml volumetric flask at the condenser exit. Now begin distillation and gradually increase the heat and collect all the distillation up to 175°C. Caution: Heating the solution above 175°C will cause sulfuric acid to distill over.

The acid in the distilling flask can be used until there is carryover of interferences or poor fluoride recovery. An occasional check of fluoride recovery with standard solutions is advised. The acid should be changed whenever there is less than 90 percent recovery or blank values are higher than 0.1 µg/ml. Note: If the sample contains chloride, add 5 mg Ag_2SO_4 to the flask for every mg of chloride. Gradually increase the heat and collect at the distillate up to 175°C. Do not exceed 175°C.

7.3.5 Determination of Concentration—Bring the distillate in the 250 ml volumetric flask to the mark with distilled water and mix thoroughly. Pipette a suitable aliquot from the distillate (containing 10 µg to 40 µg fluoride) and dilute to 50 ml with distilled water. Add 10 ml of SPADNS Mixed Reagent (see Section 6.3.12) and mix thoroughly.

After mixing, place the sample in a constant temperature bath containing the standard solution for thirty minutes before reading the absorbance with the spectrophotometer.

Set the spectrophotometer to zero absorbance at 570 nm with reference solution (6.3.11), and check the spectrophotometer calibration with the standard solution. Determine the absorbance of the samples and determine the concentration from the calibration curve. If the concentration does not fall within the range of the calibration curve, repeat the procedure using a different size aliquot.

8. *Calibration*.

Maintain a laboratory log of all calibrations.

8.1 Sampling Train.

8.1.1 Probe nozzle—Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make 3 separate measurements using different diameters each time and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.).

When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use.

Each nozzle shall be permanently and uniquely identified.

8.1.2 Pitot tube—The pitot tube shall be calibrated according to the procedure outlined in Method 2.

8.1.3 Dry gas meter and orifice meter. Both meters shall be calibrated according to the procedure outlined in APTD–0576. When diaphragm pumps with by-pass valves are used, check for proper metering system design by calibrating the dry gas meter at an additional flow rate of 0.0057 m³/min. (0.2 cfm) with the by-pass valve fully opened and then with it fully closed. If there is more than ±2 percent difference in flow rates when compared to the fully closed position of the by-pass valve, the system is not designed properly and must be corrected.

8.1.4 Probe heater calibration—The probe heating system shall be calibrated according to the procedure contained in APTD–0576. Probes constructed according to APTD–0581 need not be calibrated if the calibration curves in APTD–0576 are used.

8.1.5 Temperature gauges—Calibrate dial and liquid filled bulb thermometers against mercury-in-glass thermometers. Thermocouples need not be calibrated. For other devices, check with the Administrator.

8.2 Analytical Apparatus. Spectrophotometer. Prepare the blank standard by adding 10 ml of SPADNS mixed reagent to 50 my of distilled water. Accurately prepare a series of standards from the standard fluoride solution (see Section 6.3.9) by diluting 2, 4, 6, 8, 10, 12, and 14 ml volumes to 100 ml with distilled water. Pipette 50 ml from each solution and transfer to a 100 ml beaker. Then add 10 ml of SPADNS mixed reagent to each. These standards will contain 0, 10, 20, 30, 40, 50, 60, and 70 µg of fluoride (0—1.4 µg/ml) respectively.

After mixing, place the reference standards and reference solution in a constant temperature bath for thirty minutes before reading the absorbance with the spectrophotometer. All samples should be adjusted to this same temperature before analyzing. Since a 3°C temperature difference between samples and standards will produce an error of approximately 0.005 mg F/liter, care must be taken to see that samples and standards are at nearly identical temperatures when absorbances are recorded.

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[1] With acceptability of the test run to be based on the same criterion as in 7.1.4.

With the spectrophotometer at 570 nm, use the reference solution (see section 6.3.11) to set the absorbance to zero.

Determine the absorbance of the standards. Prepare a calibration curve by plotting μg F/50 ml versus absorbance on linear graph paper. A standard curve should be prepared initially and thereafter whenever the SPADNS mixed reagent is newly made. Also, a calibration standard should be run with each set of samples and if it differs from the calibration curve by ±2 percent, a new standard curve should be prepared.

9. *Calculations.*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

9.1 Nomenclature.

A_d=Aliquot of distillate taken for color development, ml.
A_n=Cross sectional area of nozzle, m² (ft²).
A_t=Aliquot of total sample added to still, ml.
B_{ws}=Water vapor in the gas stream, proportion by volume.
C_s=Concentration of fluoride in stack gas, mg/m³, corrected to standard conditions of 20° C, 760 mm Hg (68° F, 29.92 in. Hg) on dry basis.
F_t=Total weight of fluoride in sample, mg.
μgF=Concentration from the calibration curve, μg.
I=Percent of isokinetic sampling.
m_n=Total amount of particulate matter collected, mg.
M_w=Molecular weight of water, 18 g/g-mole (18 lb/lb-mole).
m_a=Mass of residue of acetone after evaporation, mg.
P_{bar}=Barometric pressure at the sampling site, mm Hg (in. Hg).
P_s=Absolute stack gas pressure, mm Hg (in. Hg).
P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R=Ideal gas constant, 0.06236 mm Hg-m³/°K-g-mole (21.83 in. Hg-ft³/°R-lb-mole).
T_m=Absolute average dry gas meter temperature (see fig. 13A-3), °K (°R).
T_s=Absolute average stack gas temperature (see fig. 13A-3), °K (°R).
T_{std}=Standard absolute temperature, 293° K (528° R).
V_a=Volume of acetone blank, ml.
V_{aw}=Volume of acetone used in wash, ml.
V_d=Volume of distillate collected, ml.
V_{lc}=Total volume of liquid collected in impingers and silica gel, ml. Volume of water in silica gel equals silica gel weight increase in grams times 1 ml/gram. Volume of liquid collected in impinger equals final volume minus initial volume.
V_m=Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$=Volume of gas sample measured by the dry gas meter corrected to standard conditions, dscm (dscf).
$V_{w(std)}$=Volume of water vapor in the gas sample corrected to standard conditions, scm (scf).
V_t=Total volume of sample, ml.
v_s=Stack gas velocity, calculated by Method 2, Equation 2-7 using data obtained from Method 5, m/sec (ft/sec).
W_a=Weight of residue in acetone wash, mg.
ΔH=Average pressure differential across the orifice (see fig. 13A-3), meter, mm H₂O (in. H₂O).
ρ_a=Density of acetone, mg/ml (see label on bottle).
ρ_w=Density of water, 1 g/ml (0.00220 lb/ml).
θ=Total sampling time, min.
13.6=Specific gravity of mercury.
60=Sec/min.
100=Conversion to percent.

9.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (fig. 13A-3).

9.3 Dry gas volume. Correct the sample volume measured by the dry gas meter to standard conditions [20° C, 760 mm Hg (68° F, 29.92 inches Hg)] by using equation 13A-1.

$$V_{m(std)}=V_m\frac{T_{std}}{T_m}\left[\frac{P_{bar}+\frac{\Delta H}{13.6}}{P_{std}}\right]=KV_m\frac{P_{bar}+\Delta H/13.6}{T_m}$$

equation 13A-1

where:

K=0.3855 °K/mm Hg for metric units.
=17.65 °R/in. Hg for English units.

9.4 Volume of water vapor.

$$V_{w(std)}=V_{lc}\frac{\rho_w}{M_w}\frac{RT_{std}}{P_{std}}=KV_{lc}$$

equation 13A-2

where:

K=0.00134 m³/ml for metric units.
=0.0472 ft³/ml for English units.

9.5 Moisture content.

$$B_{ws}=\frac{V_{w(std)}}{V_{m(std)}+V_{w(std)}}$$

equation 13A-3

If the liquid droplets are present in the gas stream assume the stream to be saturated and use a psychrometric chart to obtain an approximation of the moisture percentage.

9.6 Concentration.

9.6.1 Calculate the amount of fluoride in the sample according to Equation 13A-4.

$$F_t=K\frac{V_t}{A_t}\frac{V_d}{A_d}(\mu g\ F)$$

equation 13A-4

where:

$K=10^{-3}$ mg/μg.

9.6.2 Concentration of fluoride in stack gas. Determine the concentration of fluoride in the stack gas according to Equation 13A-5.

$$C_s=K\frac{F_t}{V_{m(std)}}$$

equation 13A-5

where:

K=35.31 ft³/m³.

9.7 Isokinetic variation.

9.7.1 Calculations from raw data.

$$I=\frac{100\ T_s\,[KV_{lc}+(V_m/T_m)\,(P_{bar}+\Delta H/13.6)]}{60\,\theta v_s P_s A_n}$$

equation 13A-6

where:

K=0.00346 mm Hg-m³/ml-°K for metric units.
=0.00267 in. Hg-ft³/ml-°R for English units.

9.7.2 Calculations from intermediate values.

$$I=\frac{T_s V_{m(std)} P_{std}\,100}{T_{std} v_s \theta A_n P_s\,60\,(1-B_{ws})}=K\frac{T_s V_{m(std)}}{P_s v_s A_n \theta\,(1-B_{ws})}$$

equation 13A-7

where:

K=4.323 for metric units.
=0.0944 for English units.

9.8 Acceptable results. The following range sets the limit on acceptable isokinetic sampling results:

If 90 percent <I< 110 percent, the results are acceptable. If the results are low in comparison to the standards and I is beyond the acceptable range, the Administrator may option to accept the results. Use reference 7.4 to make judgments. Otherwise, reject the results and repeat the test.

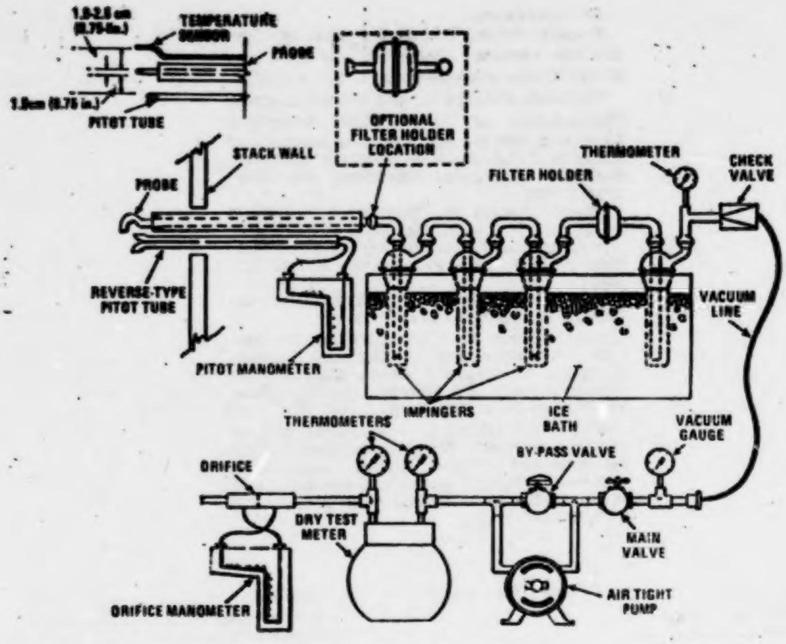
1.9-2.5 cm (0.75-1 in.)
TEMPERATURE SENSOR
PROBE
1.9cm (0.75 in.)
PITOT TUBE
OPTIONAL FILTER HOLDER LOCATION
STACK WALL
PROBE
THERMOMETER
FILTER HOLDER
CHECK VALVE
REVERSE-TYPE PITOT TUBE
VACUUM LINE
PITOT MANOMETER
IMPINGERS
ICE BATH
THERMOMETERS
VACUUM GAUGE
ORIFICE
BY-PASS VALVE
DRY TEST METER
MAIN VALVE
AIR TIGHT PUMP
ORIFICE MANOMETER

Figure 13A 1. Fluoride sampling train.

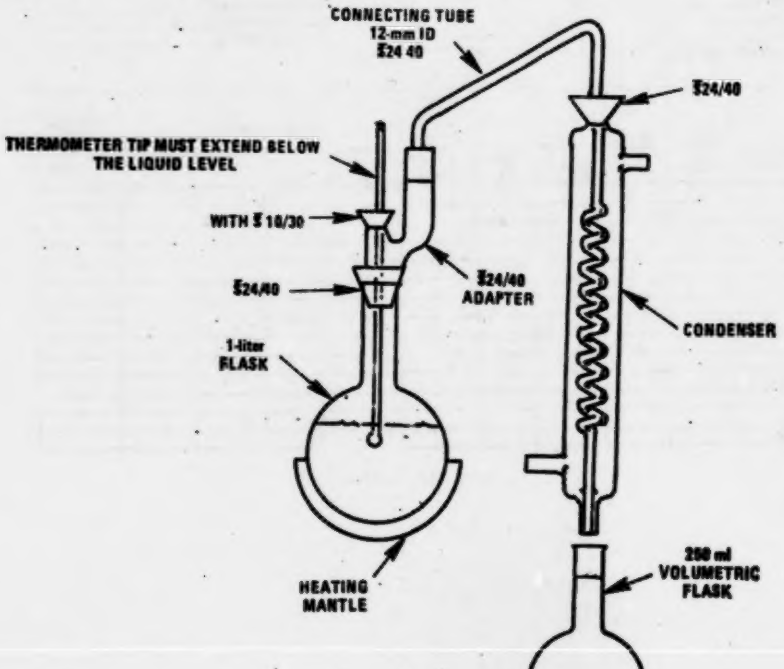
CONNECTING TUBE 12-mm ID ⧗24 40
⧗24/40
THERMOMETER TIP MUST EXTEND BELOW THE LIQUID LEVEL
WITH ⧗ 10/30
⧗24/40
⧗24/40 ADAPTER
CONDENSER
1-liter FLASK
HEATING MANTLE
250 ml VOLUMETRIC FLASK

Figure 13A-2. Fluoride Distillation Apparatus

10. *References.*

Belluck, Ervin, "Simplified Fluoride Distillation Method," *Journal of the American Water Works Association* #50: 530–6 (1958).

MacLeod, Kathryn E., and Howard L. Crist, "Comparison of the SPADNS—Zirconium Lake and Specific Ion Electrode Methods of Fluoride Determination in Stack Emission Samples," *Analytical Chemistry* 45: 1272–1273 (1973).

Martin, Robert M., "Construction Details of Isokinetic Source Sampling Equipment," Environmental Protection Agency, Air Pollution Control Office Publication No. APTD-0581.

1973 Annual Book of ASTM Standards, Part 23, Designation: D 1179–72.

Rom, Jerome J., "Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment." Environmental Protection Agency, Air Pollution Control Office Publication No. APTD-0576.

Standard Methods for the Examination of Water and Waste Water, published jointly by American Public Health Association, American Water Works Association and Water Pollution Control Federation, 13th Edition (1971).

PLANT ____________________
LOCATION ____________________
OPERATOR ____________________
DATE ____________________
RUN NO. ____________________
SAMPLE BOX NO. ____________________
METER BOX NO. ____________________
METER ΔHg ____________________
C FACTOR ____________________
PITOT TUBE COEFFICIENT, C_p ____________________

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE ____________________
BAROMETRIC PRESSURE ____________________
ASSUMED MOISTURE, % ____________________
PROBE LENGTH, m (ft) ____________________
NOZZLE IDENTIFICATION NO. ____________________
AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) ____________________
PROBE HEATER SETTING ____________________
LEAK RATE, m³/min (cfm) ____________________
PROBE LINER MATERIAL ____________________

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	STATIC PRESSURE mm Hg (in Hg)	STACK TEMPERATURE (T_S) °C (°F)	VELOCITY HEAD (ΔP_S)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER mm H_2O (in. H_2O)	GAS SAMPLE VOLUME m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		FILTER HOLDER TEMPERATURE °C (°F)	TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET °C (°F)	OUTLET °C (°F)		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 13A-3. Field data.

METHOD 13B—DETERMINATION OF TOTAL FLUORIDE EMISSIONS FROM STATIONARY SOURCES—SPECIFIC ION ELECTRODE METHOD.[14]

1. *Principle and Applicability.*

1.1 Principle. Gaseous and particulate fluorides are withdrawn isokinetically from the source using a sampling train. The fluorides are collected in the impinger water and on the filter of the sampling train. The weight of total fluorides in the train is determined by the specific ion electrode method.

1.2 Applicability. This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards. Fluorocarbons such as Freons, are not quantitatively collected or measured by this procedure.

2. *Range and Sensitivity.*

The fluoride specific ion electrode analytical method covers the range of 0.02–2,000 μg F/ml; however, measurements of less than 0.1 μg F/ml require extra care. Sensitivity has not been determined.

3. *Interferences.*

During the laboratory analysis, aluminum in excess of 300 mg/liter and silicon dioxide in excess of 300 mg/liter will precent complete recovery of fluoride.

4. *Precision, Accuracy and Stability.*

The accuracy of fluoride electrode measurements has been reported by various researchers to be in the range of 1–5 percent in a concentration range of 0.04 to 80 mg/l. A change in the temperature of the sample will change the electrode response; a change of 1°C will produce a 1.5 percent relative error in the measurement. Lack of stability in the electrometer used to measure EMF can introduce error. An error of 1 millivolt in the EMF measurement produces a relative error of 4 percent regardless of the absolute concentration being measured.

5. *Apparatus.*

5.1 Sample train. See Figure 13A–1 (Method 13A); it is similar to the Method 5 train except for the interchangeability of the position of the filter. Commercial models of this train are available. However, if one desires to build his own, complete construction details are described in APTD–0581; for changes from the APTD–0581 document and for allowable modifications to Figure 13A–1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD–0576. Since correct usage is important in obtaining valid results, all users should read the APTD–0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein.

5.1.1 Probe nozzle—Stainless steel (316) with sharp, tapered leading edge. The angle of taper shall be ≤30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. The wall thickness of the nozzle shall be less than or equal to that of 20 gauge tubing, i.e., 0.165 cm (0.065 in.) and the distance from the tip of the nozzle to the first bend or point of disturbance shall be at least two times the outside nozzle diameter. The nozzle shall be constructed from seamless stainless steel tubing. Other configurations and construction material may be used with approval from the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 cm (⅛ in.) up to 1.27 cm (½ in.) (or larger if higher volume sampling trains are used) inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in the calibration section.

5.1.2 Probe liner—Borosilicate glass or stainless steel (316). When the filter is located immediately after the probe, a probe heating system may be used to prevent filter plugging resulting from moisture condensation. The temperature in the probe shall not exceed 120±14°C (248±25°F).

5.1.3 Pitot tube—Type S, or other device approved by the Administrator,.attached to probe to allow constant monitoring of the stack gas velocity. The face openings of the pitot tube and the probe nozzle shall be adjacent and parallel to each other, not necessarily on the same plane, during sampling. The free space between the nozzle and pitot tube shall be at least 1.9 cm (0.75 in.). The free space shall be set based on a 1.3 cm (0.5 in.) ID nozzle, which is the largest size nozzle used.

The pitot tube must also meet the criteria specified in Method 2 and be calibrated according to the procedure in the calibration section of that method.

5.1.4 Differential pressure gauge—Inclined manometer capable of measuring velocity head to within 10 percent of the minimum measured value. Below a differential pressure of 1.3 mm (0.05 in.) water gauge, micromanometers with sensitivities of 0.013 mm (0.0005 in.) should be used. However, micromanometers are not easily adaptable to field conditions and are not easy to use with pulsating flow. Thus, other methods or devices acceptable to the Administrator may be used when conditions warrant.

5.1.5 Filter holder—If located between the probe and first impinger, borosilicate glass with a 20 mesh stainless steel screen filter support and a silicone rubber gasket; neither a glass frit filter support nor a sintered metal filter support may be used if the filter is in front of the impingers. If located between the third and fourth impingers, borosilicate glass with a glass frit filter support and a silicone rubber gasket. Other materials of construction may be used with approval from the Administrator, e.g., if probe liner is stainless steel, then filter holder may be stainless steel. The holder design shall provide a positive seal against leakage from the outside or around the filter.[30]

5.1.6 Filter heating system—When moisture condensation is a problem, any heating system capable of maintaining a temperature around the filter holder during sampling of no greater than 120 ± 14°C (248 ± 25°F). A temperature gauge capable of measuring temperature to within 3°C (5.4°F) shall be installed so that when the filter heater is used, the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD–0581 may be used.

5.1.7 Impingers—Four impingers connected as shown in Figure 13A–1 with ground glass (or equivalent), vacuum tight fittings. The first, third, and fourth impingers are of the Greenburg-Smith design, modified by replacing the tip with a 1¼ cm (½ in.) inside diameter glass tube extending to 1¼ cm (½ in.) from the bottom of the flask. The second impinger is of the Greenburg-Smith design with the standard tip.

5.1.8 Metering system—Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3°C (~5°F), dry gas meter with 2 percent accuracy at the required sampling rate, and related equipment, or equivalent, as required to maintain an isokinetic sampling rate and to determine sample volume. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

5.1.9 Barometer—Mercury, aneroid, or other barometers capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in Hg). In many cases, the barometric reading may be obtained from a nearby weather bureau station, in which case the station value shall be requested and an adjustment for elevation differences shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase.

5.2 Sample recovery.

5.2.1 Probe liner and probe nozzle brushes—Nylon bristles with stainless steel wire handles. The probe brush shall have extensions, at least as long as the probe, of stainless steel, teflon, or similarly inert material. Both brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

5.2.2 Glass wash bottles—Two.

5.2.3 Sample storage containers—Wide mouth, high density polyethylene bottles, 1 liter.

5.2.4 Plastic storage containers—Air tight containers of sufficient volume to store silica gel.

5.2.5 Graduated cylinder—250 ml.

5.2.6 Funnel and rubber policeman—To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

5.3 Analysis.

5.3.1 Distillation apparatus—Glass distillation apparatus assembled as shown in Figure 13A–2 (Method 13A).

5.3.2 Hot plate—Capable of heating to 500°C.

5.3.3 Electric muffle furnace—Capable of heating to 600°C.

5.3.4 Crucibles—Nickel, 75 to 100 ml capacity.

5.3.5 Beaker—1500 ml.

5.3.6 Volumetric flask—50 ml.

5.3.7 Erlenmeyer flask or plastic bottle—500 ml.

5.3.8 Constant temperature bath—Capable of maintaining a constant temperature of ±1.0°C in the range of room temperature.

5.3.9 Trip balance—300 g capacity to measure to ±0.5 g.

5.3.10 Fluoride ion activity sensing electrode.

5.3.11 Reference electrode—Single junction; sleeve type. (A combintion-type electrode having the references electrode and the fluoride-ion sensing electrode built into one unit may also be used.)

5.3.12 Electrometer—A pH meter with millivolt scale capable of ±0.1 mv resolution, or a specific ion meter made specifically for specific ion use.

5.3.13 Magnetic stirrer and TFE fluorocarbon coated stripping bars.

6. *Reagents.*

6.1 Sampling.

6.1.1 Filters—Whatman No. 1 filters, or equivalent, sized to fit filter holder.

6.1.2 Silica gel—Indicating type, 6–16 mesh. If previously used, dry at 175°C (350°F) for 2 hours. New silica gel may be used as received.

6.1.3 Water—Distilled.

6.1.4 Crushed ice.

6.1.5 Stopcock grease—Acetone insoluble, heat stable silicone grease. This is not necessary if screw-on connectors with teflon sleeves, or similar, are used.

6.2 Sample recovery.

6.2.1 Water—Distilled from same container as 6.1.3.

6.3 Analysis.

6.3.1 Calcium oxide (CaO)—Certified grade containing 0.005 percent fluoride or less.

6.3.2 Phenolphthalein Indicator—0.1 percent in 1: 1 ethanol water mixture.

6.3.3 Sodium hydroxide (NaOH)—Pellets, ACS reagent grade or equivalent.

6.3.4 Sulfuric acid (H_2SO_4)—Concentrated, ACS reagent grade or equivalent.

6.3.5 Filters—Whatman No. 541, or equivalent.

6.3.6 Water—Distilled, from same container as 6.1.3.

6.3.7 Total Ionic Strength Adjustment Buffer (TISAB)—Place aproximately 500 ml of distilled water in a 1-liter beaker. Add 57 ml glacial acetic acid, 58 g sodium chloride, and 4 g CDTA (Cyclohexylene dinitrilo tetraacetic acid). Stir to dissolve. Place the beaker in a water bath to cool it. Slowly add 5 M NaOH to the solution, measuring the pH continuously with a calibrated pH/reference electrode pair, until the pH is 5.3. Cool to room temperature. Pour into a 1-liter flask and dilute to volume with distilled water. Commercially prepared TISAB buffer may be substituted for the above.

6.3.8 Fluoride Standard Solution—0.1 M fluoride reference solution. Add 4.20 grams of reagent grade sodium fluoride (NaF) to a 1-liter volumetric flask and add enough distilled water to disolve. Dilute to volume with distilled water.

7. *Procedure.*

Note: The fusion and distillation steps of this procedure will not be required, if it can be shown to the satisfaction of the Administrator that the samples contain only water-soluble fluorides.

7.1 Sampling. The sampling shall be conducted by competent personnel experienced with this test procedure.

7.1.1 Pretest preparation. All train components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh approximately 200–300 g of silica gel in air tight containers to the nearest 0.5 g. Record the total weight, both silica gel and container, on the container. More silica gel may be used but care should be taken during sampling that it is not entrained and carried out from the impinger. As an alternative, the silica gel may be weighed directly in the impinger or its sampling holder just prior to the train assembly.

7.1.2 Preliminary determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2 and moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate calculations. Estimates may be used. However, final results will be based on actual measurements made during the test.

Select a nozzle size based on the range of velocity heads such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the differential pressure gauge is capable of measuring the minimum velocity head value to within 10 percent, or as specified by the Administrator.

Select a suitable probe liner and probe length such that all traverse points can be sampled. Consider sampling from opposite sides for large stacks to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that the sampling time per point is not less than 2 min. or select some greater time interval as specified by the Administrator, and such that the sample volume that will be taken will exceed the required minimum total gas sample volume specified in the test procedures for the specific industry. The latter is based on an approximate average sampling rate. Note also that the minimum total sample volume is corrected to standard conditions.

It is recommended that a half-integral or integral number of minutes be sample at each point in order to avoid timekeeping errors.

In some circumstances, e.g. batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

7.1.3 Preparation of collection train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and place approximately 200–300 g or more, if necessary, of preweighed silica gel in the fourth impinger. Record the weight of the silica gel and container on the data sheet. Place the empty container in a clean place for later use in the sample recovery.

Place a filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as to not allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed.

When glass liners are used, install selected nozzle using a Viton A O-ring; the Viton A O-ring is installed as a seal where the nozzle is connected to a glass liner. See APTD-0576 for details. When metal liners are used, install the nozzle as above or by a leak free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Unless otherwise specified by the Administrator, attach a temperature probe to the metal sheath of the sampling probe so that the sensor extends beyond the probe tip and does not touch any metal. Its position should be about 1.9 to 2.54 cm (0.75 to 1 in.) from the pitot tube and probe nozzle to avoid interference with the gas flow.

Assemble the train as shown in Figure 13A-1 (Method 13A) with the filter between the third and fourth impingers. Alternatively, the filter may be placed between the probe the first impinger if a 20 mesh stainless steel screen is used for the filter support. A filter heating system may be used to prevent moisture condensation, but the temperature around the filter holder shall not exceed 1200±14°C (248±25°F). [(Note: Whalman No. 1 filter decomposes at 150°C (300°F)).] Record filter location on the data sheet.[50]

Place crushed ice around the impingers.

7.1.4 Leak check procedure—After the sampling train has been assembled, turn on and set (if applicable) the probe and filter heating system(s) to reach a temperature sufficient to avoid condensation in the probe. Allow time for the temperature to stabilize. Leak check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum. A leakage rate in excess of 4% of the average sampling rate of 0.0057 m^3/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak check instruction for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until 380 mm Hg (15 in. Hg) vacuum is reached. *Do not* reverse direction of by-pass valve. This will cause water to back up into the filter holder. If 380 mm Hg (15 in. Hg) is exceeded, either leak check at this higher vacuum or end the leak check as described below and start over.

When the leak check is completed, first slowly remove the plug from the inlet to the probe or filter holder and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder (if placed before the impingers) and silica gel from being entrained backward into the third impinger.

Leak checks shall be conducted as described whenever the train is disengaged, e.g. for silica gel or filter changes during the test, prior to each test run, and at the completion of each test run. If leaks are found to be in excess of the acceptable rate, the test will be considered invalid. To reduce lost time due to leakage occurrences, it is recommended that leak checks be conducted between port changes.

7.1.5 Particulate train operation—During the sampling run, an isokinetic sampling rate within 10%, or as specified by the Administrator, of true isokinetic shall be maintained.

For each run, record the data required on the example data sheet shown in Figure 13A-3 (Method 13A). Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, and when sampling is halted. Take other data point readings at least once at each sample point during each time increment and additional readings when significant changes (20% variation in velocity head readings) necessitate additional adjustments in flow rate. Be sure to level and zero the manometer.

Clean the portholes prior to the test run to minimize chance of sampling deposited material. To begin sampling, remove the nozzle cap, verify (if applicable) that the probe heater is working and filter heater is up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available for sampling trains using type S pitot tubes with 0.85±0.02 coefficients (C_p), and when sampling in air or a stack gas with equivalent density (molecular weight, M_d, equal to 29±4), which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. APTD-0576 details the procedure for using these nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomograph unless appropriate steps are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to avoid water backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes to minimize chance of extracting deposited material.

During the test run, make periodic adjustments to keep the probe and (if applicable) filter temperatures at their proper values. Add more ice and, if necessary, salt to the ice bath, to maintain a temperature of less than 20°C (68°F) at the impinger/silica gel outlet, to avoid excessive moisture losses.

Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes high enough to make isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. After the new filter or filter assembly is installed, conduct a leak check. The final emission results shall be based on the summation of all filter catches.

A single train shall be used for the entire sample run, except for filter and silica gel changes. However, if approved by the Administrator, two or more trains may be used for a single test run when there are two or more ducts or sampling ports. The final emission results shall be based on the total of all sampling train catches.

At the end of the sample run, turn off the pump, remove the probe and nozzle from the stack, and record the final dry gas meter reading. Perform a leak check.[1] Calculate percent isokinetic (see calculation section) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

7.2 Sample recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to keep from losing part of the sample. Do not cap off the probe tip tightly while the sampling train is cooling down, as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate, if present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Ground glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Inspect the train prior to and during disassembly and note any abnormal conditions. Using a graduated cylinder, measure and record the volume of the water in the first three impingers, to the nearest ml; any condensate in the probe should be included in this determination. Treat the samples as follows:

7.2.1 Container No. 1. Transfer the impinger water from the graduated cylinder to this container. Add the filter to this container. Wash all sample exposed surfaces, including the probe tip, probe, first three impingers, impinger connectors, filter holder, and graduated cylinder thoroughly with distilled water. Wash each component three separate times with water and clean the probe and nozzle with brushes. A maximum wash of 500 ml is used, and the washings are added to the sample container which must be made of polyethylene.

7.2.2 Container No. 2. Transfer the silica gel from the fourth impinger to this container and seal.

7.3 Analysis. Treat the contents of each sample container as described below.

7.3.1 Container No. 1.

7.3.1.1 Filter this container's contents, including the Whatman No 1 filter, through Whatman No. 541 filter paper, or equivalent into a 1500 ml beaker. NOTE: If filtrate volume exceeds 900 ml make filtrate basic with NaOH to phenolphthalein and evaporate to less than 900 ml.

7.3.1.2 Place the Whatman No. 541 filter containing the insoluble matter (including the Whatman No. 1 filter) in a nickel crucible, add a few ml of water and macerate the filter with a glass rod.

Add 100 mg CaO to the crucible and mix the contents thoroughly to form a slurry. Add a couple of drops of phenolphthalein indicator. The indicator will turn red in a basic medium. The slurry should remain basic during the evaporation of the water or fluoride ion will be lost. If the indicator turns colorless during the evaporation, an acidic condition is indicated. If this happens add CaO until the color turns red again.

Place the crucible in a hood under infrared lamps or on a hot plate at low heat. Evaporate the water completely.

After evaporation of the water, place the crucible on a hot plate under a hood and slowly increase the temperature until the paper chars. It may take several hours for complete charring of the filter to occur.

Place the crucible in a cold muffle furnace and gradually (to prevent smoking) increase the temperature to 600°C, and maintain until the contents are reduced to an ash. Remove the crucible from the furnace and allow it to cool.

7.3.1.3 Add approximately 4 g of crushed NaOH to the crucible and mix. Return the crucible to the muffle furnace, and fuse the sample for 10 minutes at 600°C.

Remove the sample from the furnace and cool to ambient temperature. Using several rinsings of warm distilled water transfer the contents of the crucible to the beaker containing the filtrate from container No. 1 (7.3.1). To assure complete sample removal, rinse finally with two 20 ml portions of 25 percent (v/v) sulfuric acid and carefully add to the beaker. Mix well and transfer to a one-liter volumetric flask. Dilute to volume with distilled water and mix thoroughly. Allow any undissolved solids to settle.

7.3.2 Container No. 2. Weigh the spent silica gel and report to the nearest 0.5 g.

7.3.3 Adjustment of acid/water ratio in distillation flask—(Utilize a protective shield when carrying out this procedure). Place 400 ml of distilled water in the distilling flask and add 200 ml of concentrated H_2SO_4. Caution: Observe standard precautions when mixing the H_2SO_4 by slowly adding the acid to the flask with constant swirling. Add some soft glass beads and several small pieces of broken glass tubing and assemble the apparatus as shown in Figure 13A–2. Heat the flask until it reaches a temperature of 175°C to adjust the acid/water ratio for subsequent distillations. Discard the distillate.

7.3.4 Distillation—Cool the contents of the distillation flask to below 80°C. Pipette an aliquot of sample containing less than 0.6 mg F directly into the distilling flask and add distilled water to make a total volume of 220 ml added to the distilling flask. [For an estimate of what size aliquot does not exceed 0.6 mg F, select an aliquot of the solution and treat as described in Section 7.3.5. This will give an approximation of the fluoride content, but only an approximation since interfering ions have not been removed by the distillation step.]50

Place a 250 ml volumetric flask at the condenser exit. Now begin distillation and gradually increase the heat and collect all the distillate up to 175°C. Caution: Heating the solution above 175°C will cause sulfuric acid to distill over.

The acid in the distilling flask can be used until there is carryover of interferences or poor fluoride recovery. An occasional check of fluoride recovery with standard solutions is advised. The acid should be changed whenever there is less than 90 percent recovery or blank values are higher than 0.1 μg/ml.

7.3.5 Determination of concentration—Bring the distillate in the 250 ml volumetric flask to the mark with distilled water and mix thoroughly. Pipette a 25 ml aliquot from the distillate. Add an equal volume of TISAB and mix. The sample should be at the same temperature as the calibration standards when measurements are made. If ambient lab temperature fluctuates more than ±2°C from the temperature at which the calibration standards were measured, condition samples and standards in a constant temperature bath measurement. Stir the sample with a magnetic stirrer during measurement to minimize electrode response time. If the stirrer generates enough heat to change solution temperature, place a piece of insulating material such as cork between the stirrer and the beaker. Dilute samples (below 10^{-4} M fluoride ion content) should be held in polyethylene or polypropylene beakers during measurement.

Insert the fluoride and reference electrodes into the solution. When a steady millivolt reading is obtained, record it. This may take several minutes. Determine concentration from the calibration curve. Between electrode measurements, soak the fluoride sensing electrode in distilled water for 30 seconds and then remove and blot dry.

8. *Calibration.*

Maintain a laboratory log of all calibrations.

8.1 Sampling Train.

8.1.1 Probe nozzle—Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make 3 separate measurements using different diameters each time and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.).

When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use.

Each nozzle shall be permanently and uniquely identified.

8.1.2 Pitot tube—The pitot tube shall be calibrated according to the procedure outlined in Method 2.

8.1.3 Dry gas meter and orifice meter. Both meters shall be calibrated according to the procedure outlined in APTD–0576. When diaphragm pumps with by-pass valves are used, check for proper metering system design by calibrating the dry gas meter at an additional flow rate of 0.0057 m³/min. (0.2 cfm) with the by-pass valve fully opened and then with it fully closed. If there is more than ±2 percent difference in flow rates when compared to the fully closed position of the by-pass valve, the system is not designed properly and must be corrected.

8.1.4 Probe heater calibration—The probe heating system shall be calibrated according to the procedure contained in APTD–0576. Probes constructed according to APTD–0581 need not be calibrated if the calibration curves in APTD–0576 are used.

8.1.5 Temperature gauges—Calibrate dial and liquid filled bulb thermometers against mercury-in-glass thermometers. Thermocouples need not be calibrated. For other devices, check with the Administrator.

8.2 Analytical Apparatus.

8.2.1 Fluoride Electrode—Prepare fluoride standardizing solutions by serial dilution of the 0.1 M fluoride standard solution. Pipette 10 ml of 0.1 M NaF into a 100 ml volumetric flask and make up to the mark with distilled water for a 10^{-2} M standard solution. Use 10 ml of 10^{-2} M solution to make a 10^{-3} M solution in the same manner. Repeat for 10^{-4} and 10^{-5} M solutions.

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[1] With acceptability of the test run to be based on the same criterion as in 7.1.4.

Pipette 50 ml of each standard into a separate beaker. Add 50 ml of TISAB to each beaker. Place the electrode in the most dilute standard solution. When a steady millivolt reading is obtained, plot the value on the linear axis of semi-log graph paper versus concentration on the log axis. Plot the nominal value for concentration of the standard on the log axis, e.g., when 50 ml of 10^{-2} M standard is diluted with 50 ml TISAB, the concentration is still designated "10^{-2} M".

Between measurements soak the fluoride sensing electrode in distilled water for 30 seconds, and then remove and blot dry. Analyze the standards going from dilute to concentrated standards. A straight-line calibration curve will be obtained, with nominal concentrations of 10^{-5}, 10^{-4}, 10^{-3}, 10^{-2}, 10^{-1} fluoride molarity on the log axis plotted versus electrode potential (in millivolts) on the linear scale.

Calibrate the fluoride electrode daily, and check it hourly. Prepare fresh fluoride standardizing solutions daily of 10^{-2} M or less. Store fluoride standardizing solutions in polyethylene or polypropylene containers. (Note: Certain specific ion meters have been designed specifically for fluoride electrode use and give a direct readout of fluoride ion concentration. These meters may be used in lieu of calibration curves for fluoride measurements over narrow concentration ranges. Calibrate the meter according to manufacturer's instructions.)

9. *Calculations.*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

9.1 Nomenclature.

A_n=Cross sectional area of nozzle, m^2 (ft^2).
A_t=Aliquot of total sample added to still, ml.
B_{ws}=Water vapor in the gas stream, proportion by volume.
C_s=Concentration of fluoride in stack gas, mg/m^3, corrected to standard conditions of 20° C, 760 mm Hg (68° F, 29.92 in. Hg) on dry basis.
F_t=Total weight of fluoride in sample, mg.
I=Percent of isokinetic sampling.
M=Concentration of fluoride from calibration curve, molarity.
m_n=Total amount of particulate matter collected, mg.
M_w=Molecular weight of water, 18 g/g-mole (18 lb/lb-mole).
m_a=Mass of residue of acetone after evaporation, mg.
P_{bar}=Barometric pressure at the sampling site, mm Hg (in. Hg).
P_s=Absolute stack gas pressure, mm Hg (in. Hg).
P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R=Ideal gas constant, 0.06236 mm Hg-m^3/°K-g-mole (21.83 in. Hg-ft^3/°R-lb-mole).
T_m=Absolute average dry gas meter temperature (see fig. 13A-3), °K (°R).
T_s=Absolute average stack gas temperature (see fig. 13A-3), °K (°R).
T_{std}=Standard absolute temperature, 293° K (528° R).
V_a=Volume of acetone blank, ml.
V_{aw}=Volume of acetone used in wash, ml.
V_d=Volume of distillate collected, ml.
V_{lc}=Total volume of liquid collected in impingers and silica gel, ml. Volume of water in silica gel equals silica gel weight increase in grams times 1 ml/gram. Volume of liquid collected in impinger equals final volume minus initial volume.
V_m=Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$=Volume of gas sample measured by the dry gas meter corrected to standard conditions, dscm (dscf).
$V_{w(std)}$=Volume of water vapor in the gas sample corrected to standard conditions, scm (scf).
V_t=Total volume of sample, ml.
v_s=Stack gas velocity, calculated by Method 2, Equation 2-7 using data obtained from Method 5, m/sec (ft/sec).
W_a=Weight of residue in acetone wash, mg.
ΔH=Average pressure differential across the orifice (see fig. 13A-3), meter, mm H_2O (in. H_2O).
ρ_a=Density of acetone, mg/ml (see label on bottle).
ρ_w=Density of water, 1 g/ml (0.00220 lb/ml).
θ=Total sampling time, min.
13.6=Specific gravity of mercury.
60=Sec/min.
100=Conversion to percent.

9.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 13A-3 of Method 13A).

9.3 Dry gas volume. Use Section 9.3 of Method 13A.

9.4 Volume of Water Vapor. Use Section 9.4 of Method 13A.

9.5 Moisture Content. Use Section 9.5 of Method 13A.

9.6 Concentration

9.6.1 Calculate the amount of fluoride in the sample according to equation 13B-1.

$$F_t = K \frac{V_t}{A_t} (V_d)\ (M)$$

where:

K=19 mg/ml.

9.6.2 Concentration of fluoride in stack gas. Use Section 9.6.2 of Method 13A.

9.7 Isokinetic variation. Use Section 9.7 of Method 13A.

9.8 Acceptable results. Use Section 9.8 of Method 13A.

10. *References.*

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1973 Annual Book of ASTM Standards, Part 23, Designation: D 1179-72.

Pom, Jerome J., "Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment," Environmental Protection Agency, Air Pollution Control Office Publication No. APTD-0576.

Standard Methods for the Examination of Water and Waste Water, published jointly by American Public Health Association, American Water Works Association and Water Pollution Control Federation, 13th Edition (1971).

METHOD 14—DETERMINATION OF FLUORIDE EMISSIONS FROM POTROOM ROOF MONITORS OF PRIMARY ALUMINUM PLANTS 27

1. *Principle and applicability.*

1.1 *Principle.* Gaseous and particulate fluoride roof monitor emissions are drawn into a permanent sampling manifold through several large nozzles. The sample is transported from the sampling manifold to ground level through a duct. The gas in the duct is sampled using Method 13A or 13B—DETERMINATION OF TOTAL FLUORIDE EMISSIONS FROM STATIONARY SOURCES. Effluent velocity and volumetric flow rate are determined with anemometers permanently located in the roof monitor.

1.2 *Applicability.* This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards.

2. *Apparatus.*

2.1.1 *Anemometers.* Vane or propeller anemometers with a velocity measuring threshold as low as 15 meters/minute and a range up to at least 600 meters/minute. Each anemometer shall generate an electrical signal which can be calibrated to the velocity measured by the anemometer. Anemometers shall be able to withstand dusty and corrosive atmospheres.

One anemometer shall be installed for every 85 meters of roof monitor length. If the roof monitor length divided by 85 meters is not a whole number, round the fraction to the nearest whole number to determine the number of anemometers needed. Use one anemometer for any roof monitor less than 85 meters long. Permanently mount the anemometers at the center of each equal length along the roof monitor. One anemometer shall be installed in the same section of the roof monitor that contains the sampling manifold (see section 2.2.1). Make a velocity traverse of the width of the roof monitor where an anemometer is to be placed. This traverse may be made with any suitable low velocity measuring device, and shall be made during normal process operating conditions. Install the anemometer at a point of average velocity along this traverse.

2.1.2 *Recorders.* Recorders equipped with signal transducers for converting the electrical signal from each anemometer to a continuous recording of air flow velocity, or to an integrated measure of volumetric flow. For the purpose of recording velocity, "continuous" shall mean one readout per 15-minute or shorter time interval. A constant amount of time shall elapse between readings. Volumetric flow rate may be determined by an electrical count of anemometer revolutions. The recorders or counters shall permit identification of the velocities or flow rate measured by each individual anemometer.

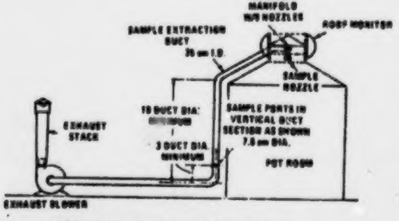
SAMPLE MANIFOLD W/NOZZLES
ROOF MONITOR
SAMPLE EXTRACTION DUCT 30 cm I.D.
SAMPLE NOZZLE
10 DUCT DIA. MINIMUM
EXHAUST STACK
SAMPLE PORTS IN VERTICAL DUCT SECTION AS SHOWN 7.6 cm DIA.
3 DUCT DIA. MINIMUM
POT ROOM
EXHAUST BLOWER

Figure 14-1. Roof Monitor Sampling System

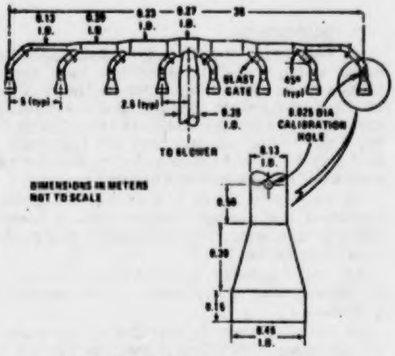

Figure 14-2. Sampling Manifold and Nozzles.

2.2 Roof monitor air sampling system.

2.2.1 *Sampling ductwork.* The manifold system and connecting duct shall be permanently installed to draw an air sample from the roof monitor to ground level. A typical installation of duct for drawing a sample from a roof monitor to ground level is shown in Figure 14-1. A plan of a manifold system that is located in a roof monitor is shown in Figure 14-2. These drawings represent a typical installation for a generalized roof monitor. The dimensions on these figures may be altered slightly to make the manifold system fit into a particular roof monitor, but the general configuration shall be followed. There shall be eight nozzles, each having a diameter of 0.40 to 0.50 meters. The length of the manifold system from the first nozzle to the eighth shall be 35 meters or eight percent of the length of the roof monitor, whichever is greater. The duct leading from the roof monitor manifold shall be round with a diameter of 0.30 to 0.40 meters. As shown in Figure 14-2, each of the sample legs of the manifold shall have a device, such as a blast gate or valve, to enable adjustment of flow into each sample nozzle.

Locate the manifold along the length of the roof monitor so that it lies near the midsection of the roof monitor. If the design of a particular roof monitor makes this impossible, the manifold may be located elsewhere along the roof monitor, but avoid locating the manifold near the ends of the roof monitor or in a section where the aluminum reduction pot arrangement is not typical of the rest of the potroom. Center the sample nozzles in the throat of the roof monitor. (See Figure 14-1.) Construct all sample-exposed surfaces within the nozzles, manifold and sample duct of 316 stainless steel. Aluminum may be used if a new ductwork system is conditioned with fluoride-laden roof monitor air for a period of six weeks prior to initial testing. Other materials of construction may be used if it is demonstrated through comparative testing that there is no loss of fluorides in the system. All connections in the ductwork shall be leak free.

Locate two sample ports in a vertical section of the duct between the roof monitor and exhaust fan. The sample ports shall be at least 10 duct diameters downstream and two diameters upstream from any flow disturbance such as a bend or contraction. The two sample ports shall be situated 90° apart. One of the sample ports shall be situated so that the duct can be traversed in the plane of the nearest upstream duct bend.

2.2.2 *Exhaust fan.* An industrial fan or blower to be attached to the sample duct at ground level. (See Figure 14-1.) This exhaust fan shall have a maximum capacity such that a large enough volume of air can be pulled through the ductwork to maintain an isokinetic sampling rate in all the sample nozzles for all flow rates normally encountered in the roof monitor.

The exhaust fan volumetric flow rate shall be adjustable so that the roof monitor air can be drawn isokinetically into the sample nozzles. This control of flow may be achieved by a damper on the inlet to the exhauster or by any other workable method.

2.3 Temperature measurement apparatus.

2.3.1 *Thermocouple.* Installed in the roof monitor near the sample duct.

2.3.2 *Signal transducer.* Transducer to change the thermocouple voltage output to a temperature readout.

2.3.3 *Thermocouple wire.* To reach from roof monitor to signal transducer and recorder.

2.3.4 *Sampling train.* Use the train described in Methods 13A and 13B—Determination of total fluoride emissions from stationary sources.

3. Reagents.

3.1 *Sampling and analysis.* Use reagents described in Method 13A or 13B—Determination of total fluoride emissions from stationary sources.

4. Calibration.

4.1 *Propeller anemometer.* Calibrate the anemometers so that their electrical signal output corresponds to the velocity or volumetric flow they are measuring. Calibrate according to manufacturer's instructions.

4.2 *Manifold intake nozzles.* Adjust the exhaust fan to draw a volumetric flow rate (refer to Equation 14-1) such that the entrance velocity into each manifold nozzle approximates the average effluent velocity in the roof monitor. Measure the velocity of the air entering each nozzle by inserting an S type pitot tube into a 2.5 cm or less diameter hole (see Figure 14-2) located in the manifold between each blast gate (or valve) and nozzle. The pitot tube tip shall be extended into the center of the manifold. Take care to insure that there is no leakage around the pitot probe which could affect the indicated velocity in the manifold leg. If the velocity of air being drawn into each nozzle is not the same, open or close each blast gate (or valve) until the velocity in each nozzle is the same. Fasten each blast gate (or valve) so that it will remain in this position and close the pitot port holes. This calibration shall be performed when the manifold system is installed. (Note: It is recommended that this calibration be repeated at least once a year.)

5. Procedure.

5.1 *Roof monitor velocity determination.*

5.1.1 *Velocity value for setting isokinetic flow.* During the 24 hours preceding a test run, determine the velocity indicated by the propeller anemometer in the section of roof monitor containing the sampling manifold. Velocity readings shall be taken every 15 minutes or at shorter equal time intervals. Calculate the average velocity for the 24-hour period.

5.1.2 *Velocity determination during a test run.* During the actual test run, record the velocity or volume readings of each propeller anemometer in the roof monitor. Velocity readings shall be taken for each anemometer every 15 minutes or at shorter equal time intervals (or continuously).

5.2 *Temperature recording.* Record the temperature of the roof monitor every two hours during the test run.

5.3 *Sampling.*

5.3.1 *Preliminary air flow in duct.* During the 24 hours preceding the test, turn on the exhaust fan and draw roof monitor air through the manifold duct to condition the ductwork. Adjust the fan to draw a volumetric flow through the duct such that the velocity of gas entering the manifold nozzles approximates the average velocity of the air leaving the roof monitor.

5.3.2 *Isokinetic sample rate adjustment.* Adjust the fan so that the volumetric flow rate in the duct is such that air enters into the manifold sample nozzles at a velocity equal to the 24-hour average velocity determined under 5.1.1. Equation 14-1 gives the correct stream velocity which is needed in the duct at the sample ports in order for sample gas to be drawn isokinetically into the manifold nozzles. Perform a pitot traverse of the duct at the sample ports to determine if the correct average velocity in the duct has been achieved. Perform the pitot determination according to Method 2. Make this determination before the start of a test run. The fan setting need not be changed during the run.

$$V_d = \frac{8\ (D_n)^2}{(D_d)^2}\ (V_m)\ \frac{1\ \text{minute}}{60\ \text{sec}}$$

where:

V_d=desired velocity in duct at sample ports, meter/sec.

D_n=diameter of a roof monitor manifold nozzle, meters.

D_d=diameter of duct at sample port, meters.

V_m=average velocity of the air stream in the roof monitor, meters/minute, as determined under section 5.1.1.

5.2.3 *Sample train operation*. Sample the duct using the standard fluoride train and methods described in Methods 13A and 13B—Determination of total fluoride emissions from stationary sources. Select sample traverse points according to Method 1. If a selected sampling point is less than one inch from the stack wall, adjust the location of that point to one inch away from the wall.

5.3.4 *Each test run shall last eight hours or more*. If a question exists concerning the representativeness of an eight-hour test, a longer test period up to 24 hours may be selected. Conduct each run during a period when all normal operations are performed underneath the sampling manifold, i.e. tapping, anode changes, maintenance, and other normal duties. All pots in the potroom shall be operated in a normal manner during the test period.

5.3.5 *Sample recovery*. Same as Method 13A or 13B—Determination of total fluoride emissions from stationary sources.

5.4 *Analysis*. Same as Method 13A or 13B—Determination of total fluoride emissions from stationary sources.

6. Calculations.

6.1 *Isokinetic sampling test*. Calculate the mean velocity measured during each sampling run by the anemometer in the section of the roof monitor containing the sampling manifold. If the mean velocity recorded during a particular test run does not fall within ±20 percent of the mean velocity established according to 5.3.2, repeat the run.

6.2 *Average velocity of roof monitor gases*. Calculate the average roof monitor velocity using all the velocity or volumetric flow readings from section 5.1.2.

6.3 *Roof monitor temperature*. Calculate the mean value of the temperatures recorded in section 5.2.

6.4 *Concentration of fluorides in roof monitor air in mg F/m³*. This is given by Equation 13A-5 in Method 13A—Determination of total fluoride emissions from stationary sources.

6.5 Average volumetric flow from roof is given by Equation 14-2.

$$Q_m \doteq \frac{V_{mt}\ (A)\ (M_d)\ P_m\ (294^\circ\text{K})}{(T_m + 273^\circ)\ (760\ \text{mm Hg})}$$

where:

Q_m=average volumetric flow from roof monitor at standard conditions on a dry basis, m³/min.

A=roof monitor open area, m².

V_{mt}=average velocity of air in the roof monitor, meters/minute, from section 6.2.

P_m=atmospheric pressure, mm Hg.

T_m=roof monitor temperature, °C, from section 6.3.

M_d=mole fraction of dry gas, which is given by $M_d = \frac{100 - 100\ (B_{wo})}{100}$

B_{wo}=is the proportion by volume of water vapor in the gas stream, from Equation 13A-3, Method 13A—Determination of total fluoride emissions from stationary sources.

METHOD 15. DETERMINATION OF HYDROGEN SULFIDE, CARBONYL SULFIDE, AND CARBON DISULFIDE EMISSIONS FROM STATIONARY SOURCES [86]

INTRODUCTION

The method described below uses the principle of gas chromatographic separation and flame photometric detection (FPD). Since there are many systems or sets of operating conditions that represent usable methods of determining sulfur emissions, all systems which employ this principle, but differ only in details of equipment and operation, may be used as alternative methods, provided that the criteria set below are met.

1. Principle and applicability

1.1 Principle. A gas sample is extracted from the emission source and diluted with clean dry air. An aliquot of the diluted sample is then analyzed for hydrogen sulfide (H_2S), carbonyl sulfide (COS), and carbon disulfide (CS_2) by gas chromatographic (GC) separation and flame photometric detection (FPD).

1.2 Applicability. This method is applicable for determination of the above sulfur compounds from tail gas control units of sulfur recovery plants.

2. Range and sensitivity

2.1 Range. Coupled with a gas chromtographic system utilizing a 1-milliliter sample size, the maximum limit of the FPD for each sulfur compound is approximately 10 ppm. It may be necessary to dilute gas samples from sulfur recovery plants hundredfold (99:1) resulting in an upper limit of about 1000 ppm for each compound.

2.2 The minimum detectable concentration of the FPD is also dependent on sample size and would be about 0.5 ppm for a 1 ml sample.

3. Interferences

3.1 Moisture Condensation. Moisture condensation in the sample delivery system, the analytical column, or the FPD burner block can cause losses or interferences. This potential is eliminated by heating the sample line, and by conditioning the sample with dry dilution air to lower its dew point below the operating temperature of the GC/FPD analytical system prior to analysis.

3.2 Carbon Monoxide and Carbon Dioxide. CO and CO_2 have substantial desensitizing effects on the flame photometric detector even after 9:1 dilution. (Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluding CO and CO_2 before any of the sulfur compounds to be measured.) Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without CO_2 in the diluent gas. The CO_2 level should be approximately 10 percent for the case with CO_2 present. The two chromatographs should show agreement within the precision limits of section 4.1.

3.3 Elemental Sulfur. The condensation of sulfur vapor in the sampling line can lead to eventual coating and even blockage of the sample line. This problem can be eliminated along with the moisture problem by heating the sample line.

4. Precision

4.1 Calibration Precision. A series of three consecutive injections of the same calibration gas, at any dilution, shall produce results which do not vary by more than ±13 percent from the mean of the three injections.

4.2 Calibration Drift. The calibration drift determined from the mean of three injections made at the beginning and end of any 8-hour period shall not exceed ±5 percent.

5. Apparatus

5.1.1 Probe. The probe must be made of inert material such as stainless steel or glass. It should be designed to incorporate a filter and to allow calibration gas to enter the probe at or near the sample entry point. Any portion of the probe not exposed to the stack gas must be heated to prevent moisture condensation.

5.1.2 The sample line must be made of Teflon,[1] no greater than 1.3 cm (½ in) inside diameter. All parts from the probe to the dilution system must be thermostatically heated to 120° C.

5.1.3 Sample Pump. The sample pump shall be a leakless Teflon coated diaphragm type or equivalent. If the pump is upstream of the dilution system, the pump head must be heated to 120° C.

5.2 Dilution System. The dilution system must be constructed such that all sample contacts are made of inert material (e.g. stainless steel or Teflon). It must be heated to 120° C and be capable of approximately a 9:1 dilution of the sample.

5.3 Gas Chromatograph. The gas chromatograph must have at least the following components:

5.3.1 Oven. Capable of maintaining the separation column at the proper operating temperature ±1° C.

5.3.2 Temperature Gauge. To monitor column oven, detector, and exhaust temperature ±1° C.

5.3.3 Flow System. Gas metering system to measure sample, fuel, combustion gas, and carrier gas flows.

5.3.4 Flame Photometric Detector.

5.3.4.1 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

5.3.4.2 Power Supply. Capable of delivering up to 750 volts.

5.3.4.3 Recorder. Compatible with the output voltage range of the electrometer.

5.4 Gas Chromatograph Columns. The column system must be demonstrated to be capable of resolving three major reduced sulfur compounds: H_2S, COS, and CS_2.

To demonstrate that adequate resolution has been achieved the tester must submit a chromatograph of a calibration gas containing all three reduced sulfur compounds in the concentration range of the applicable standard. Adequate resolution will be defined as base line separation of adjacent peaks when the amplifier attenuation is set so that the smaller peak is at least 50 percent of full scale. Base line separation is defined as a return to zero ±5 percent in the interval between peaks. Systems not meeting this criteria may be considered alternate methods subject to the approval of the Administrator.

5.5.1 Calibration System. The calibration system must contain the following components.

5.5.2 Flow System. To measure air flow over permeation tubes at ±2 percent. Each flowmeter shall be calibrated after a complete test series with a wet test meter. If the flow measuring device differs from the wet test meter by 5 percent, the completed test shall be discarded. Alternatively, the tester may elect to use the flow data that would yield the lowest flow measurement. Calibration with a wet test meter before a test is optional.

5.5.3 Constant Temperature Bath. Device capable of maintaining the permeation tubes at the calibration temperature within ±1.1° C.

5.5.4 Temperature Gauge. Thermometer or equivalent to monitor bath temperature within ±1° C.

6. Reagents

6.1 Fuel. Hydrogen (H_2) prepurified grade or better.

6.2 Combustion Gas. Oxygen (O_2) or air, research purity or better.

6.3 Carrier Gas. Prepurified grade or better.

6.4 Diluent. Air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons.

6.5 Calibration Gases. Permeation tubes, one each of H_2S, COS, and CS_2, gravimetrically calibrated and certified at some convenient operating temperature. These tubes consist of hermetically sealed FEP Teflon tubing in which a liquified gaseous substance is enclosed. The enclosed gas permeates through the tubing wall at a constant rate. When the temperature is constant, calibration gases covering a wide range of known concentrations can be generated by varying and accurately measuring the flow rate of diluent gas passing over the tubes. These calibration gases are used to calibrate the GC/FPD system and the dilution system.

7. Pretest Procedures

The following procedures are optional but would be helpful in preventing any problem which might occur later and invalidate the entire test.

7.1 After the complete measurement system has been set up at the site and deemed to be operational, the following procedures should be completed before sampling is initiated.

7.1.1 Leak Test. Appropriate leak test procedures should be employed to verify the integrity of all components, sample lines, and connections. The following leak test procedure is suggested: For components upstream of the sample pump, attach the probe end of the sample line to a manometer or vacuum gauge, start the pump and pull greater than 50 mm (2 in.) Hg vacuum, close off the pump outlet, and then stop the pump and ascertain that there is no leak for 1 minute. For components after the pump, apply a slight positive pressure and check for leaks by applying a liquid (detergent in water, for example) at each joint. Bubbling indicates the presence of a leak.

7.1.2 System Performance. Since the complete system is calibrated following each test, the precise calibration of each component is not critical. However, these components should be verified to be operating properly. This verification can be performed by observing the response of flowmeters or of the GC output to changes in flow rates or calibration gas concentrations and ascertaining the response to be within predicted limits. If any component or the complete system fails to respond in a normal and predictable manner, the source of the discrepancy should be identifed and corrected before proceeding.

8. Calibration

Prior to any sampling run, calibrate the system using the following procedures. (If more than one run is performed during any 24-hour period, a calibration need not be performed prior to the second and any subsequent runs. The calibration must, however, be verified as prescribed in section 10, after the last run made within the 24-hour period.)

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[1] Mention of trade names or specific products does not constitute an endorsement by the Environmental Protection Agency.

8.1 General Considerations. This section outlines steps to be followed for use of the GC/FPD and the dilution system. The procedure does not include detailed instructions because the operation of these systems is complex, and it requires an understanding of the individual system being used. Each system should include a written operating manual describing in detail the operating procedures associated with each component in the measurement system. In addition, the operator shuld be familiar with the operating principles of the components; particularly the GC/FPD. The citations in the Bibliography at the end of this method are recommended for review for this purpose.

8.2 Calibration Procedure. Insert the permeation tubes into the tube chamber. Check the bath temperature to assure agreement with the calibration temperature of the tubes within ±0.1°C. Allow 24 hours for the tubes to equilibrate. Alternatively equilibration may be verified by injecting samples of calibration gas at 1-hour intervals. The permeation tubes can be assumed to have reached equilibrium when consecutive hourly samples agree within the precision limits of section 4.1.

Vary the amount of air flowing over the tubes to produce the desired concentrations for calibrating the analytical and dilution systems. The air flow across the tubes must at all times exceed the flow requirement of the analytical systems. The concentration in parts per million generated by a bube containing a specific permeant can be calculated as follows:

$$C=K\times P_r/ML$$

Equation 15-1

where:
- C=Concentration of permeant produced in ppm.
- P_r=Permeation rate of the tube in µg/min.
- M=Molecular weight of the permeant: g/g-mole.
- L=Flow rate, l/min, of air over permeant @ 20°C, 760 mm Hg.
- K=Gas constant at 20°C and 760 mm Hg=24.04 l/g mole.

8.3 Calibration of analysis system. Generate a series of three or more known concentrations spanning the linear range of the FPD (approximately 0.05 to 1.0 ppm) for each of the four major sulfur compounds. Bypassing the dilution system, inject these standards in to the GC/FPD analyzers and monitor the responses. Three injects for each concentration must yield the precision described in section 4.1. Failure to attain this precision is an indication of a problem in the calibration or analytical system. Any such problem must be identified and corrected before proceeding.

8.4 Calibration Curves. Plot the GC/FPD response in current (amperes) versus their causative concentrations in ppm on log-log coordinate graph paper for each sulfur compound. Alternatively, a least squares equation may be generated from the calibration data.

8.5 Calibration of Dilution System. Generate a know concentration of hydrogen sulfied using the permeation tube system. Adjust the flow rate of diluent air for the first dilution stage so that the desired level of dilution is approximated. Inject the diluted calibration gas into the GC/FPD system and monitor its response. Three injections for each dilution must yield the precision described in section 4.1. Failure to attain this precision in this step is an indication of a problem in the dilution system. Any such problem must be identified and corrected before proceeding. Using the calibration data for H_2S (developed under 8.3) determine the diluted calibration gas concentration in ppm. Then calculate the dilution factor as the ratio of the calibration gas concentration before dilution to the diluted calibration gas concentration determined under this paragraph. Repeat this procedure for each stage of dilution required. Alternatively, the GC/FPD system may be calibrated by generating a series of three or more concentrations of each sulfur compound and diluting these samples before injecting them into the GC/FPD system. This data will then serve as the calibration data for the unknown samples and a separate determination of the dilution factor will not be necessary. However, the precision requirements of section 4.1 are still applicable.

9. Sampling and Analysis Procedure

9.1 Sampling. Insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Begin sampling and dilute the sample approximately 9:1 using the dilution system. Note that the precise dilution factor is that which is determined in paragraph 8.5. Condition the entire system with sample for a minimum of 15 minutes prior to commencing analysis.

9.2 Analysis. Aliquots of diluted sample are injected into the GC/FPD analyzer for analysis.

9.2.1 Sample Run. A sample run is composed of 16 individual analyses (injects) performed over a period of not less than 3 hours or more than 6 hours.

9.2.2 Observation for Clogging of Probe. If reductions in sample concentrations are observed during a sample run that cannot be explained by process conditions, the sampling must be interrupted to determine if the sample probe is clogged with particulate matter. If the probe is found to be clogged, the test must be stopped and the results up to that point discarded. Testing may resume after cleaning the probe or replacing it with a clean one. After each run, the sample probe must be inspected and, if necessary, dismantled and cleaned.

10. Post-Test Procedures

10.1 Sample Line Loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ±20 percent, must be introduced into the sampling system at the opening of the probe in sufficient quantities to ensure that there is an excess of sample which must be vented to the atmosphere. The sample must be transported through the entire sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss. A sampling system loss of more than 20 percent is unacceptable. Sampling losses of 0-20 percent must be corrected by dividing the resulting sample concentration by the fraction of recovery. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.

10.2 Recalibration. After each run, or after a series of runs made within a 24-hour period, perform a partial recalibration using the procedures in section 8. Only H_2S (or other permeant) need be used to recalibrate the GC/FPD analysis system (8.3) and the dilution system (8.5).

10.3 Determination of Calibration Drift. Compare the calibration curves obtained prior to the runs, to the calibration curves obtained under paragraph 10.1. The calibration drift should not exceed the limits set forth in paragraph 4.2. If the drift exceeds this limit, the intervening run or runs should be considered not valid. The tester, however, may instead have the option of choosing the calibration data set which would give the highest sample values.

11. Calculations

11.1 Determine the concentrations of each reduced sulfur compound detected directly from the calibration curves. Alternatively, the concentrations may be calculated using the equation for the least squares line.

11.2 Calculation of SO_2 Equivalent. SO_2 equivalent will be determined for each analysis made by summing the concentrations of each reduced sulfur compound resolved during the given analysis.

$$SO_2 \text{ equivalent}=\Sigma(H_2S,\ COS,\ 2\ CS_2)d$$

Equation 15-2

where:
- SO_2 equivalent=The sum of the concentration of each of the measured compounds (COS, H_2S, CS_2) expressed as sulfur dioxide in ppm.
- H_2S=Hydrogen sulfide, ppm.
- COS=Carbonyl sulfide, ppm.
- CS_2=Carbon disulfide, ppm.
- d=Dilution factor, dimensionless.

11.3 Average SO_2 equivalent will be determined as follows:

$$\text{Average } SO_2 \text{ equivalent} = \frac{\sum_{i=1}^{N} SO_2 \text{ equiv.}_i}{N\ (1 - Bwo)}$$

Equation 15-3

where:
- Average SO_2 equivalent=Average SO_2 equivalent in ppm, dry basis.
- Average SO_2 equivalent$_i$=SO_2 in ppm as determined by Equation 15-2.
- N=Number of analyses performed.
- Bwo=Fraction of volume of water vapor in the gas stream as determined by Method 4—Determination of Moisture in Stack Gases (36 FR 24887).

12. Example System

Described below is a system utilized by EPA in gathering NSPS data. This system does not now reflect all the latest developments in equipment and column technology, but it does represent one system that has been demonstrated to work.

12.1 Apparatus.

12.1.1 Sample System.

12.1.1.1 Probe. Stainless steel tubing, 6.35 mm (¼ in.) outside diameter, packed with glass wool.

12.1.1.2 Sample Line. 3/16 inch inside diameter Teflon tubing heated to 120° C. This temperature is controlled by a thermostatic heater.

12.1.1.3 Sample Pump. Leakless Teflon coated diaphragm type or equivalent. The pump head is heated to 120° C by enclosing it in the sample dilution box (12.2.4 below).

12.1.2 Dilution System. A schematic diagram of the dynamic dilution system is given in Figure 15-2. The dilution system is constructed such that all sample contacts are made of inert materials. The dilution system which is heated to 120° C must be capable of a minimum of 9:1 dilution of sample. Equipment used in the dilution system is listed below:

12.1.2.1 Dilution Pump. Model A-150 Kohmyhr Teflon positive displacement type, nonadjustable 150 cc/min. ±2.0 percent, or equivalent, per dilution stage. A 9:1 dilution of sample is accomplished by combining 150 cc of sample with 1350 cc of clean dry air as shown in Figure 15-2.

12.1.2.2 Valves. Three-way Teflon solenoid or manual type.

12.1.2.3 Tubing. Teflon tubing and fittings are used throughout from the sample probe to the GC/FPD to present an inert surface for sample gas.

12.1.2.4 Box. Insulated box, heated and maintained at 120° C, of sufficient dimensions to house dilution apparatus.

12.1.2.5 Flowmeters. Rotameters or equivalent to measure flow from 0 to 1500 ml/min. ±1 percent per dilution stage.

12.1.3.0 Gas Chromatograph.

12.1.3.1 Column—1.83 m (6 ft.) length of Teflon tubing, 2.16 mm (0.085 in.) inside diameter, packed with deactivated silica gel, or equivalent.

12.1.3.2 Sample Valve. Teflon six port gas sampling valve, equipped with a 1 ml sample loop, actuated by compressed air (Figure 15-1).

12.1.3.3 Oven. For containing sample valve, stripper column and separation column. The oven should be capable of maintaining an elevated temperature ranging from ambient to 100° C, constant within ±1° C.

12.1.3.4 Temperature Monitor. Thermocouple pyrometer to measure column oven, detector, and exhaust temperature ±1° C.

12.1.3.5 Flow System. Gas metering system to measure sample flow, hydrogen flow, oxygen flow and nitrogen carrier gas flow.

12.1.3.6 Detector. Flame photometric detector.

12.1.3.7 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

12.1.3.8 Power Supply. Capable of delivering up to 750 volts.

12.1.3.9 Recorder. Compatible with the output voltage range of the electrometer.

12.1.4 Calibration. Permeation tube system (Figure 15-3).

12.1.4.1 Tube Chamber. Glass chamber of sufficient dimensions to house permeation tubes.

12.1.4.2 Mass Flowmeters. Two mass flowmeters in the range 0-3 l/min. and 0-10 l/min. to measure air flow over permeation tubes at ±2 percent. These flowmeters shall be cross-calibrated at the beginning of each test. Using a convenient flow rate in the measuring range of both flowmeters, set and monitor the flow rate of gas over the permeation tubes. Injection of calibration gas generated at this flow rate as measured by one flowmeter followed by injection of calibration gas at the same flow rate as measured by the other flowmeter should agree within the specified precision limits. If they do not, then there is a problem with the mass flow measurement. Each mass flowmeter shall be calibrated prior to the first test with a wet test meter and thereafter at least once each year.

12.1.4.3 Constant Temperature Bath. Capable of maintaining permeation tubes at certification temperature of 30° C within ±0.1° C.

12.2 Reagents.

12.2.1 Fuel. Hydrogen (H_2) prepurified grade or better.

12.2.2 Combustion Gas. Oxygen (O_2) research purity or better.

12.2.3 Carrier Gas. Nitrogen (N_2) prepurified grade or better.

12.2.4 Diluent. Air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons, and filtered using MSA filters 46727 and 79030, or equivalent. Removal of sulfur compounds can be verified by injecting dilution air only, described in section 8.3.

12.2.5 Compressed Air. 60 psig for GC valve actuation.

12.2.6 Calibration Gases. Permeation tubes gravimetrically calibrated and certified at 30.0° C.

12.3 Operating Parameters. The operating parameters for the GC/FPD system are as follows: nitrogen carrier gas flow rate of 100 cc/min, exhaust temperature of 110° C, detector temperature 105° C, oven temperature of 40° C, hydrogen flow rate of 80 cc/minute, oxygen flow rate of 20 cc/minute, and sample flow rate of 80 cc/minute.

12.4 Analysis. The sample valve is actuated for 1 minute in which time an aliquot of diluted sample is injected onto the separation column. The valve is then deactivated for the remainder of analysis cycle in which time the sample loop is refilled and the separation column continues to be foreflushed. The elution time for each compound will be determined during calibration.

13. Bibliography

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13.3 Mulick, J. D., R. K. Stevens, and R. Baumgardner. "An Analytical System Designed to Measure Multiple Malodorous Compounds Related to Kraft Mill Activities." Presented at the 12tn Conference on Methods in Air Pollution and Industrial Hygiene Studies, University of Southern California, Los Angeles, Calif. April 6-8, 1971.

13.4 Devonald, R. H., R. S. Serenius, and A. D. McIntyre. "Evaluation of the Flame Photometric Detector for Analysis of Sulfur Compounds." Pulp and Paper Magazine of Canada, 73,3 (March, 1972).

13.5 Grimley, K. W., W. S. Smith, and R. M. Martin. "The Use of a Dynamic Dilution System in the Conditioning of Stack Gases for Automated Analysis by a Mobile Sampling Van" Presented at the 63rd Annual APCA Meeting in St. Louis, Mo. June 14-19, 1970.

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METHOD 16. SEMICONTINUOUS DETERMINATION OF SULFUR EMISSIONS FROM STATIONARY SOURCES 82

Introduction

The method described below uses the principle of gas chromatographic separation and flame photometric detection. Since there are many systems or sets of operating conditions that represent usable methods of determining sulfur emissions, all systems which employ this principle, but differ only in details of equipment and operation, may be used as alternative methods, provided that the criteria set below are met.

1. *Principle and Applicability.*

1.1 Principle. A gas sample is extracted from the emission source and diluted with clean dry air. An aliquot of the diluted sample is then analyzed for hydrogen sulfide (H_2S), methyl mercaptan (MeSH), dimethyl sulfide (DMS) and dimethyl disulfide (DMDS) by gas chromatographic (GC) separation and flame photometric detection (FPD). These four compounds are known collectively as total reduced sulfur (TRS).

1.2 Applicability. This method is applicable for determination of TRS compounds from recovery furnaces, lime kilns, and smelt dissolving tanks at kraft pulp mills.

2. *Range and Sensitivity.*

2.1 Range. Coupled with a gas chromatographic system utilizing a ten milliliter sample size, the maximum limit of the FPD for each sulfur compound is approximately 1 ppm. This limit is expanded by dilution of the sample gas before analysis. Kraft mill gas samples are normally diluted tenfold (9:1), resulting in an upper limit of about 10 ppm for each compound.

For sources with emission levels between 10 and 100 ppm, the measuring range can be best extended by reducing the sample size to 1 milliliter.

2.2 Using the sample size, the minimum detectable concentration is approximately 50 ppb.

3. *Interferences.*

3.1 Moisture Condensation. Moisture condensation in the sample delivery system, the analytical column, or the FPD burner block can cause losses or interferences. This potential is eliminated by heating the sample line, and by conditioning the sample with dry dilution air to lower its dew point below the operating temperature of the GC/FPD analytical system prior to analysis.

3.2 Carbon Monoxide and Carbon Dioxide. CO and CO_2 have substantial desensitizing effect on the flame photometric detector even after 9:1 dilution. Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluting these compounds before any of the compounds to be measured. Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without CO_2 in the diluent gas. The CO_2 level should be approximately 10 percent for the case with CO_2 present. The two chromatographs should show agreement within the precision limits of Section 4.1.

3.3 Particulate Matter. Particulate matter in gas samples can cause interference by eventual clogging of the analytical system. This interference must be eliminated by use of a probe filter.

3.4 Sulfur Dioxide. SO_2 is not a specific interferent but may be present in such large amounts that it cannot be effectively separated from other compounds of interest. The procedure must be designed to eliminate this problem either by the choice of separation columns or by removal of SO_2 from the sample.

Compliance with this section can be demonstrated by submitting chromatographs of calibration gases with SO_2 present in the same quantities expected from the emission source to be tested. Acceptable systems shall show baseline separation with the amplifier attenuation set so that the reduced sulfur compound of concern is at least 50 percent of full scale. Base line separation is defined as a return to zero ± percent in the interval between peaks.

4. *Precision and Accuracy.*

4.1 GC/FPD and Dilution System Calibration Precision. A series of three consecutive injections of the same calibration gas, at any dilution, shall produce results which do not vary by more than ±3 percent from the mean of the three injections.

4.2 GC/FPD and Dilution System Calibration Drift. The calibration drift determined from the mean of three injections made at the beginning and end of any 8-hour period shall not exceed ± percent.

4.3 System Calibration Accuracy. The complete system must quantitatively transport and analyze with an accuracy of 20 percent. A correction factor is developed to adjust calibration accuracy to 100 percent.

5. *Apparatus* (See Figure 16–1).

5.1.1 Probe. The probe must be made of inert material such as stainless steel or glass. It should be designed to incorporate a filter and to allow calibration gas to enter the probe at or near the sample entry point. Any portion of the probe not exposed to the stack gas must be heated to prevent moisture condensation.

5.1.2 Sample Line. The sample line must be made of Teflon,[1] no greater than 1.3 cm (½) inside diameter. All parts from the probe to the dilution system must be thermostatically heated to 120° C.

5.1.3 Sample Pump. The sample pump shall be a leakless Teflon-coated diaphragm type or equivalent. If the pump is upstream of the dilution system, the pump head must be heated to 120° C.

5.2 Dilution System. The dilution system must be constructed such that all sample contacts are made of inert materials (e.g., stainless steel or Teflon). It must be heated to 120° C. and be capable of approximately a 9:1 dilution of the sample.

5.3 Gas Chromatograph. The gas chromatograph must have at least the following components:

5.3.1 Oven. Capable of maintaining the separation column at the proper operating temperature ±1° C.

5.3.2 Temperature Gauge. To monitor column oven, detector, and exhaust temperature ±1° C.

5.3.3 Flow System. Gas metering system to measure sample, fuel, combustion gas, and carrier gas flows.

5.3.4 Flame Photometric Detector.

5.3.4.1 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

5.3.4.2 Power Supply. Capable of delivering up to 750 volts.

5.3.4.3 Recorder. Compatible with the output voltage range of the electrometer.

5.4 Gas Chromatograph Columns. The column system must be demonstrated to be capble of resolving the four major reduced sulfur compounds: H_2S, MeSH, DMS, and DMDS. It must also demonstrate freedom from known interferences.

To demonstrate that adequate resolution has been achieved, the tester must submit a chromatograph of a calibration gas containing all four of the TRS compounds in the concentration range of the applicable standard. Adequate resolution will be defined as base line separation of adjacent peaks when the amplifier attenuation is set so that the smaller peak is at least 50 percent of full scale. Base line separation is defined in Section 3.4. Systems not meeting this criteria may be considered alternate methods subject to the approval of the Administrator.

5.5. Calibration System. The calibration system must contain the following components.

5.5.1 Tube Chamber. Chamber of glass or Teflon of sufficient dimensions to house permeation tubes.

5.5.2 Flow System. To measure air flow over permeation tubes at ±2 percent. Each flowmeter shall be calibrated after a complete test series with a wet test meter. If the flow measuring device differs from the wet test meter by 5 percent, the completed test shall be discarded. Alternatively, the tester may elect to use the flow data that would yield the lowest flow measurement. Calibration with a wet test meter before a test is optional.

5.5.3 Constant Temperature Bath. Device capable of maintaining the permeation tubes at the calibration temperature within ±0.1° C.

5.5.4 Temperature Gauge. Thermometer or equivalent to monitor bath temperature within ±1° C.

6. *Reagents.*

6.1 Fuel. Hydrogen (H_2) prepurified grade or better.

6.2 Combustion Gas. Oxygen (O_2) or air, research purity or better.

6.3 Carrier Gas. Prepurified grade or better.

6.4 Diluent. Air containing less than 50 ppb total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons. This gas must be heated prior to mixing with the sample to avoid water condensation at the point of contact.

6.5 Calibration Gases. Permeation tubes, one each of H_2S, MeSH, DMS, and DMDS, agravimetrically calibrated and certified at some convenient operating temperature. These tubes consist of hermetically sealed FEP Teflon tubing in which a liquified gaseous substance is enclosed. The enclosed gas permeates through the tubing wall at a constant rate. When the temperature is constant, calibration gases coverning a wide range of known concentrations can be generated by varying and accurately measuring the flow rate of diluent gas passing over the tubes. These calibration gases are used to calibrate the GC/FPD system and the dilution system.

7. *Pretest Procedures.* The following procedures are optional but would be helpful in preventing any problem which might occur later and invalidate the entire test.

7.1 After the complete measurement system has been set up at the site and deemed to be operational, the following procedures should be completed before sampling is initiated.

7.1.1 Leak Test. Appropriate leak test procedures should be employed to verify the integrity of all components, sample lines, and connections. The following leak test procedure is suggested: For components upstream of the sample pump, attach the probe end of the sample line to a ma- nometer or vacuum gauge, start the pump and pull greater than 50 mm (2 in.) Hg vacuum, close off the pump outlet, and then stop the pump and ascertain that there is no leak for 1 minute. For components after the pump, apply a slight positive pressure and check for leaks by applying a liquid (detergent in water, for example) at each joint. Bubbling indicates the presence of a leak.

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[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

7.1.2 System Performance. Since the complete system is calibrated following each test, the precise calibration of each component is not critical. However, these components should be verified to be operating properly. This verification can be performed by observing the response of flowmeters or of the GC output to changes in flow rates or calibration gas concentrations and ascertaining the response to be within predicted limits. In any component, or if the complete system fails to respond in a normal and predictable manner, the source of the discrepancy should be identified and corrected before proceeding.

8. *Calibration*. Prior to any sampling run, calibrate the system using the following procedures. (If more than one run is performed during any 24-hour period, a calibration need not be performed prior to the second and any subsequent runs. The calibration must, however, be verified as prescribed in Section 10, after the last run made within the 24-hour period.)

8.1 General Considerations. This section outlines steps to be followed for use of the GC/FPD and the dilution system. The procedure does not include detailed instructions because the operation of these systems is complex, and it requires a understanding of the individual system being used. Each system should include a written operating manual describing in detail the operating procedures associated with each component in the measurement system. In addition, the operator should be familiar with the operating principles of the components; particularly the GC/FPD. The citations in the Bibliography at the end of this method are recommended for review for this purpose.

8.2 Calibration Procedure. Insert the permeation tubes into the tube chamber. Check the bath temperature to assure agreement with the calibration temperature of the tubes within ±0.1° C. Allow 24 hours for the tubes to equilibrate. Alternatively equilibration may be verified by injecting samples of calibration gas at 1-hour intervals. The permeation tubes can be assumed to have reached equilibrium when consecutive hourly samples agree within the precision limits of Section 4.1.

Vary the amount of air flowing over the tubes to produce the desired concentrations for calibrating the analytical and dilution systems. The air flow across the tubes must at all times exceed the flow requirement of the analytical systems. The concentration in parts per million generated by a tube containing a specific permeant can be calculated as follows:

$$C = K \frac{P_r}{ML}$$

Equation 16-1

where:

C=Concentration of permeant produced in ppm.

P_r=Permeation rate of the tube in µg/min.

M=Molecular weight of the permeant (g/g-mole).

L=Flow rate, 1/min, of air over permeant @ 20° C, 760 mm Hg.

K=Gas constant at 20° C and 760 mm Hg=24.04 1/g mole.

8.3 Calibration of analysis system. Generate a series of three or more known concentrations spanning the linear range of the FPD (approximately 0.05 to 1.0 ppm) for each of the four major sulfur compounds. Bypassing the dilution system, inject these standards into the GC/FPD analyzers and monitor the responses. Three injects for each concentration must yield the precision described in Section 4.1. Failure to attain this precision is an indication of a problem in the calibration or analytical system. Any such problem must be identified and corrected before proceeding.

8.4 Calibration Curves. Plot the GC/FPD response in current (amperes) versus their causative concentrations in ppm on log-log coordinate graph paper for each sulfur compound. Alternatively, a least squares equation may be generated from the calibration data.

8.5 Calibration of Dilution System. Generate a known concentration of hydrogen sulfide using the permeation tube system. Adjust the flow rate of diluent air for the first dilution stage so that the desired level of dilution is approximated. Inject the diluted calibration gas into the GC/FPD system and monitor its response. Three injections for each dilution must yield the precision described in Section 4.1. Failure to attain this precision in this step is an indication of a problem in the dilution system. Any such problem must be identified and corrected before proceeding. Using the calibration data for H_2S (developed under 8.3) determine the diluted calibration gas concentration in ppm. Then calculate the dilution factor as the ratio of the calibration gas concentration before dilution to the diluted calibration gas concentration determined under this paragraph. Repeat this procedure for each stage of dilution required. Alternatively, the GC/FPD system may be calibrated by generating a series of three or more concentrations of each sulfur compound and diluting these samples before injecting them into the GC/FPD system. This data will then serve as the calibration data for the unknown samples and a separate determination of the dilution factor will not be necessary. However, the precision requirements of Section 4.1 are still applicable.

9. *Sampling and Analysis Procedure.*

9.1 Sampling. Insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Begin sampling and dilute the sample approximtely 9:1 using the dilution system. Note that the precise dilution factor is that which is determined in paragraph 8.5. Condition the entire system with sample for a minimum of 15 minutes prior to commencing analysis.

9.2 Analysis. Aliquots of diluted sample are injected into the GC/FPD analyzer for analysis.

9.2.1 Sample Run. A sample run is composed of 16 individual analyses (injects) performed over a period of not less than 3 hours or more than 6 hours.

9.2.2 Observation for Clogging of Probe. If reductions in sample concentrations are observed during a sample run that cannot be explained by process conditions, the sampling must be interrupted to determine if the sample probe is clogged with particulate matter. If the probe is found to be clogged, the test must be stopped and the results up to that point discarded. Testing may resume after cleaning the probe or replacing it with a clean one. After each run, the sample probe must be inspected and, if necessary, dismantled and cleaned.

10. *Post-Test Procedures.*

10.1 Sample line loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ± 20 percent, must be introduced into the sampling system in sufficient quantities to insure that there is an excess of sample which must be vented to the atmosphere. The sample must be introduced immediately after the probe and filter and transported through the remainder of the sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss.[9]

For sampling losses greater than 20 percent in a sample run, the sample run is not to be used when determining the arithmetic mean of the performance test. For sampling losses of 0–20 percent, the sample concentration must be corrected by dividing the sample concentration by the fraction of recovery. The fraction of recovery is equal to one minus the ratio of the measured concentration to the known concentration of hydrogen sulfide in the sample line loss procedure. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.[9]

10.2 Recalibration. After each run, or after a series of runs made within a 24-hour period, perform a partial recalibration using the procedures in Section 8. Only H_2S (or other permeant) need be used to recalibrate the GC/FPD analysis system (8.3) and the dilution system (8.5).

10.3 Determination of Calibration Drift. Compare the calibration curves obtained prior to the runs, to the calibration curves obtained under paragraph 10.1. The calibration drift should not exceed the limits set forth in paragraph 4.2. If the drift exceeds this limit, the intervening run or runs should be considered not valid. The tester, however, may instead have the option of choosing the calibration data set which would give the highest sample values.

11. *Calculations.*

11.1 Determine the concentrations of each reduced sulfur compound detected directly from the calibration curves. Alternatively, the concentrations may be calculated using the equation for the least square line.

11.2 Calculation of TRS. Total reduced sulfur will be determined for each anaylsis made by summing the concentrations of each reduced sulfur compound resolved during a given analysis.

$$TRS = \Sigma\,(H_2S,\ MeSH,\ DMS,\ 2DMDS)d$$

Equation 16-2

where:

TRS=Total reduced sulfur in ppm, wet basis.

H_2S=Hydrogen sulfide, ppm.

MeSH=Methyl mercaptan, ppm.

DMS=Dimethyl sulfide, ppm.

DMDS=Dimethyl disulfide, ppm.

d=Dilution factor, dimensionless.

11.3 Average TRS. The average TRS will be determined as follows:

$$\text{Average TRS} = \frac{\sum_{i=1}^{N} TRS_i}{N(1-B_{wo})}$$

Average TRS = Average total reduced suflur in ppm, dry basis.
TRS_i = Total reduced sulfur in ppm as determined by Equation 16-2.
N = Number of samples.
B_{wo} = Fraction of volume of water vapor in the gas stream as determined by method 4—Determination of Moisture in Stack Gases (36 FR 24887).

11.4 Average concentration of individual reduced sulfur compounds.

$$C = \frac{\sum_{i=1}^{N} S_i}{N}$$

Equation 16-3

where:

S_i = Concentration of any reduced sulfur compound from the ith sample injection, ppm.
C = Average concentration of any one of the reduced sulfur compounds for the entire run, ppm.
N = Number of injections in any run period.

12. *Example System.* Described below is a system utilized by EPA in gathering NSPS data. This system does not now reflect all the latest developments in equipment and column technology, but it does represent one system that has been demonstrated to work.

12.1 Apparatus.

12.1.1 Sampling System.

12.1.1.1 Probe. Figure 16-1 illustrates the probe used in lime kilns and other sources where significant amounts of particulate matter are present. the probe is designed with the deflector shield placed between the sample and the gas inlet holes and the glass wool plugs to reduce clogging of the filter and possible adsorption of sample gas. The exposed portion of the probe between the sampling port and the sample line is heated with heating tape.

12.1.1.2 Sample Line $^3/_{16}$ inch inside diameter Teflon tubing, heated to 120° C. This temperature is controlled by a thermostatic heater.

12.1.1.3 Sample Pump. Leakless Teflon coated diaphragm type or equivalent. The pump head is heated to 120° C by enclosing it in the sample dilution box (12.2.4 below).

12.1.2 Dilution System. A schematic diagram of the dynamic dilution system is given in Figure 16-2. The dilution system is constructed such that all sample contacts are made of inert materials. The dilution system which is heated to 120° C must be capable of a minimum of 9:1 dilution of sample. Equipment used in the dilution system is listed below:

12.1.2.1 Dilution Pump. Model A-150 Kohmyhr Teflon positive displacement type, nonadjustable 150 cc/min. ±2.0 percent, or equivalent, per dilution stage. A 9:1 dilution of sample is accomplished by combining 150 cc of sample with 1,350 cc of clean dry air as shown in Figure 16-2.

12.1.2.2 Valves. Three-way Teflon solenoid or manual type.

12.1.2.3 Tubing. Teflon tubing and fittings are used throughout from the sample probe to the GC/FPD to present an inert surface for sample gas.

12.1.2.4 Box. Insulated box, heated and maintained at 120° C, of sufficient dimensions to house dilution apparatus.

12.1.2.5 Flowmeters. Rotameters or equivalent to measure flow from 0 to 1500 ml/min ±1 percent per dilution stage.

12.1.3 Gas Chromatograph Columns. Two types of columns are used for separation of low and high molecular weight sulfur compounds:

12.1.3.1 Low Molecular Weight Sulfur Compounds Column (GC/FPD-1).

12.1.3.1 Separation Column. 11 m by 2.16 mm (36 ft by 0.085 in) inside diameter Teflon tubing packed with 30/60 mesh Teflon coated with 5 percent polyphenyl ether and 0.05 percent orthophosphoric acid, or equivalent (see Figure 16-3).

12.1.3.1.2 Stripper or Precolumn. 0.6 m by 2.16 mm (2 ft by 0.085 in) inside diameter Teflon tubing packed as in 5.3.1.

12.1.3.1.3 Sample Valve. Teflon 10-port gas sampling valve, equipped with a 10 ml sample loop, actuated by compressed air (Figure 16-3).

12.1.3.1.4 Oven. For containing sample valve, stripper column and separation column. The oven should be capable of maintaining an elevated temperature ranging from ambient to 100° C, constant within ±1° C.

12.1.3.1.5 Temperature Monitor. Thermocouple pyrometer to measure column oven, detector, and exhaust temperature ±1° C.

12.1.3.1.6 Flow System. Gas metering system to measure sample flow, hydrogen flow, and oxygen flow (and nitrogen carrier gas flow).

12.1.3.1.7 Detector. Flame photometric detector.

12.1.3.1.8 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

12.1.3.1.9 Power Supply. Capable of delivering up to 750 volts.

12.1.3.1.10 Recorder. Compatible with the output voltage range of the electrometer.

12.1.3.2 High Molecular Weight Compounds Column (GC/FPD-11).

12.1.3.2.1. Separation Column. 3.05 m by 2.16 mm (10 ft by 0.0885 in) inside diameter Teflon tubing packed with 30/60 mesh Teflon coated with 10 percent Triton X-305, or equivalent.

12.1.3.2.2 Sample Valve. Teflon 6-port gas sampling valve equipped with a 10 ml sample loop, actuated by compressed air (Figure 16-3).

12.1.3.2.3 Other Components. All components same as in 12.1.3.1.4 to 12.1.3.1.10.

12.1.4 Calibration. Permeation tube system (figure 16-4).

12.1.4.1 Tube Chamber. Glass chamber of sufficient dimensions to house permeation tubes.

12.1.4.2 Mass Flowmeters. Two mass flowmeters in the range 0-3 1/min. and 0-10 1/min. to measure air flow over permeation tubes at ±2 percent. These flowmeters shall be cross-calibrated at the beginning of each test. Using a convenient flow rate in the measuring range of both flowmeters, set and monitor the flow rate of gas over the permeation tubes. Injection of calibration gas generated at this flow rate as measured by one flowmeter followed by injection of calibration gas at the same flow rate as measured by the other flowmeter should agree within the specified precision limits. If they do not, then there is a problem with the mass flow measurement. Each mass flowmeter shall be calibrated prior to the first test with a wet test meter and thereafter, at least once each year.

12.1.4.3 Constant Temperature Bath. Capable of maintaining permeation tubes at certification temperature of 30° C. within ±0.1° C.

12.2 Reagents

12.2.1 Fuel. Hydrogen (H_2) prepurified grade or better.

12.2.2. Combustion Gas. Oxygen (O_2) research purity or better.

12.2.3 Carrier Gas. Nitrogen (N_2) prepurified grade or better.

12.2.4 Diluent. Air containing less than 50 ppb total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons, and filtered using MSA filters 46727 and 79030, or equivalent. Removal of sulfur compounds can be verified by injecting dilution air only, described in Section 8.3.

12.2.5 Compressed Air. 60 psig for GC valve actuation.

12.2.6 Calibrated Gases. Permeation tubes gravimetrically calibrated and certified at 30.0° C.

12.3 Operating Parameters.

12.3.1 Low-Molecular Weight Sulfur Compounds. The operating parameters for the GC/FPD system used for low molecular weight compounds are as follows: nitrogen carrier gas flow rate of 50 cc/min, exhaust temperature of 110° C, detector temperature of 105° C, oven temperature of 40° C, hydrogen flow rate of 80 cc/min, oxygen flow rate of 20 cc/min, and sample flow rate between 20 and 80 cc/min.

12.3.2 High-Molecular Weight Sulfur Compounds. The operating parameters for the GC/FPD system for high molecular weight compounds are the same as in 12.3.1 except: oven temperature of 70° C, and nitrogen carrier gas flow of 100 cc/min.

12.4 Analysis Procedure.

12.4.1 Analysis. Aliquots of diluted sample are injected simultaneously into both GC/FPD analysers for analysis. GC/FPD-I is used to measure the low-molecular weight reduced sulfur compounds. The low molecular weight compounds include hydrogen sulfide, methyl mercaptan, and dimethyl sulfide. GC/FPD-II is used to resolve the high-molecular weight compound. The high-molecular weight compound is dimethyl disulfide.

12.4.1.1 Analysis of Low-Molecular Weight Sulfur Compounds. The sample valve is actuated for 3 minutes in which time an aliquot of diluted sample is injected into the stripper column and analytical column. The valve is then deactivated for approximately 12 minutes in which time, the analytical column continues to be foreflushed, the stripper column is backflushed, and the sample loop is refilled. Monitor the responses. The elution time for each compound will be determined during calibration.

12.4.1.2 Analysis of High-Molecular Weight Sulfur Compounds. The procedure is essentially the same as above except that no stripper column is needed.

13. *Bibliography.*

13.1 O'Keeffe, A. E. and G. C. Ortman. "Primary Standards for Trace Gas Analysis." Analytical Chemical Journal, 38,760 (1966).

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13.3 Mulick, J. D., R. K. Stevens, and R. Baumgardner. "An Analytical System Designed to Measure Multiple Malodorous Compounds Related to Kraft Mill Activities." Presented at the 12th Conference on Methods in Air Pollution and Industrial Hygiene Studies, University of Southern California, Los Angeles, CA. April 6-8, 1971.

13.4 Devonald, R. H., R. S. Serenius, and A. D. McIntyre. "Evaluation of the Flame

Photometric Detector for Analysis of Sulfur Compounds." Pulp and Paper Magazine of Canada, 73,3 (March, 1972).

13.5 Grimley, K. W., W. S. Smith, and R. M. Martin. "The Use of a Dynamic Dilution System in the Conditioning of Stack Gases for Automated Analysis by a Mobile Sampling Van." Presented at the 63rd Annual APCA Meeting in St. Louis, Mo. June 14-19, 1970.

13.6 General Reference. Standard Methods of Chemical Analysis Volume III A and B Instrumental Methods. Sixth Edition. Van Nostrand Reinhold Co.

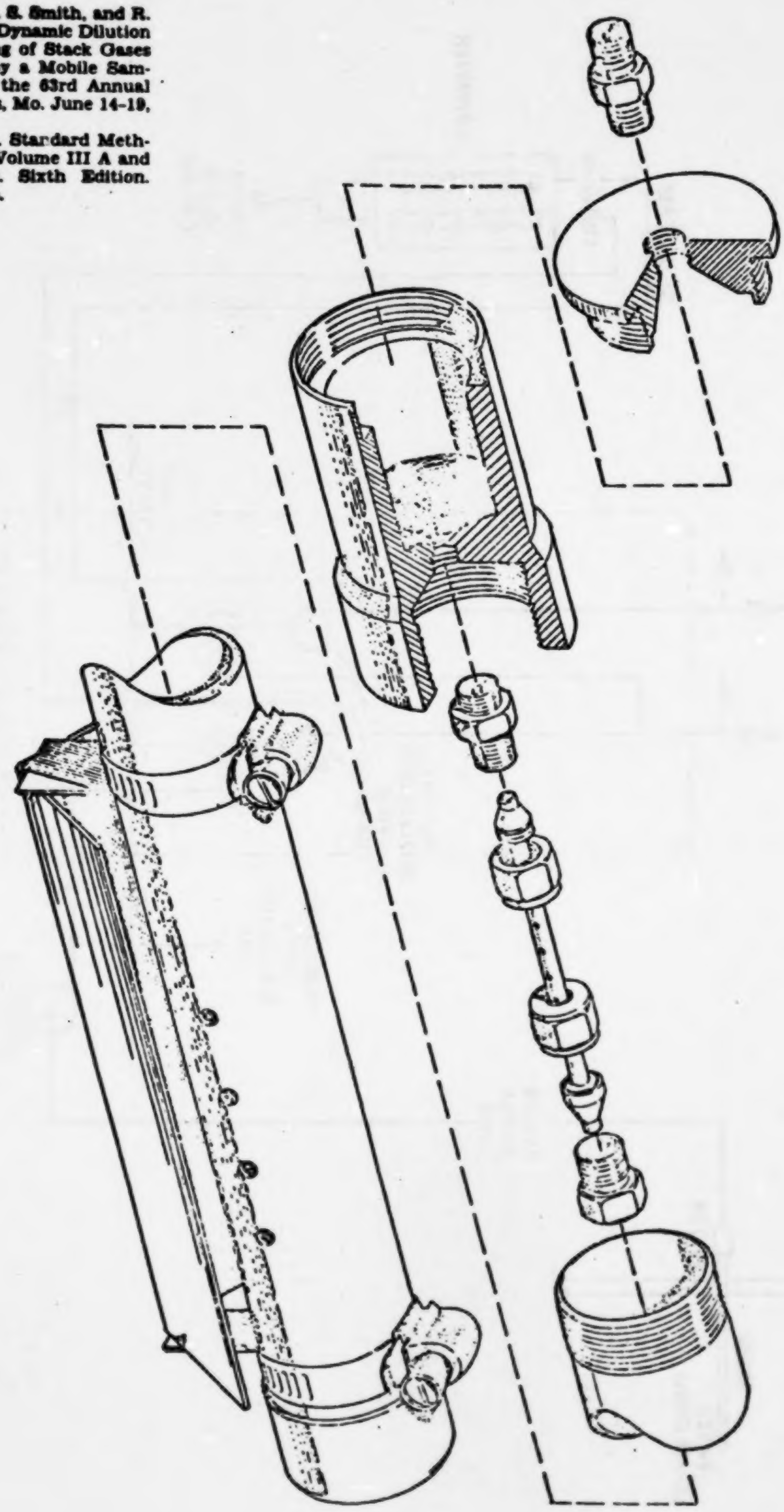


Figure 16-1. Probe used for sample gas containing high particulate loadings.

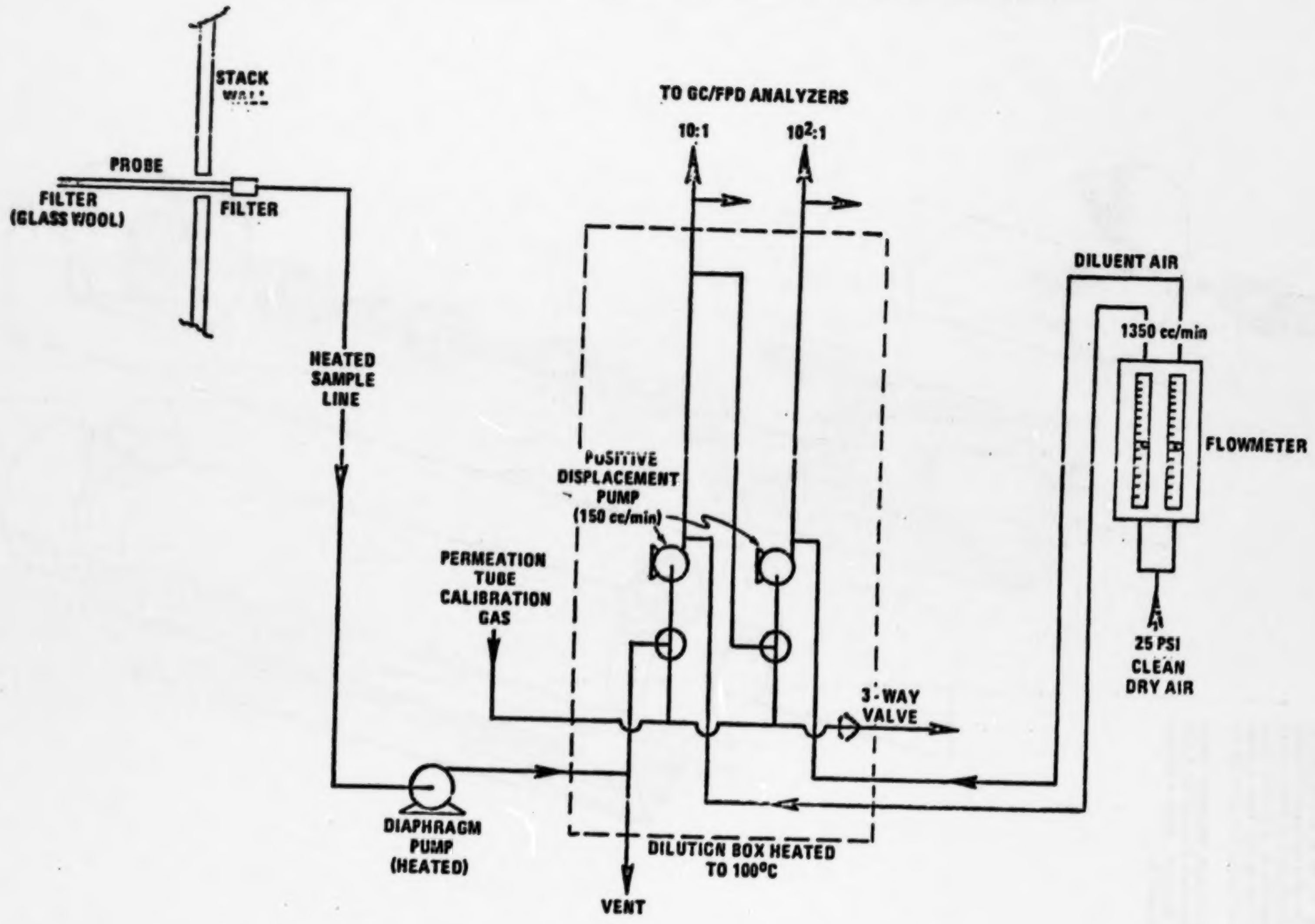

STACK WALL
PROBE
FILTER (GLASS WOOL)
FILTER
HEATED SAMPLE LINE
DIAPHRAGM PUMP (HEATED)
PERMEATION TUBE CALIBRATION GAS
POSITIVE DISPLACEMENT PUMP (150 cc/min)
TO GC/FPD ANALYZERS
10:1
10²:1
3-WAY VALVE
DILUTION BOX HEATED TO 100°C
VENT
DILUENT AIR
1350 cc/min
FLOWMETER
25 PSI CLEAN DRY AIR

Figure 16-2. Sampling and dilution apparatus.

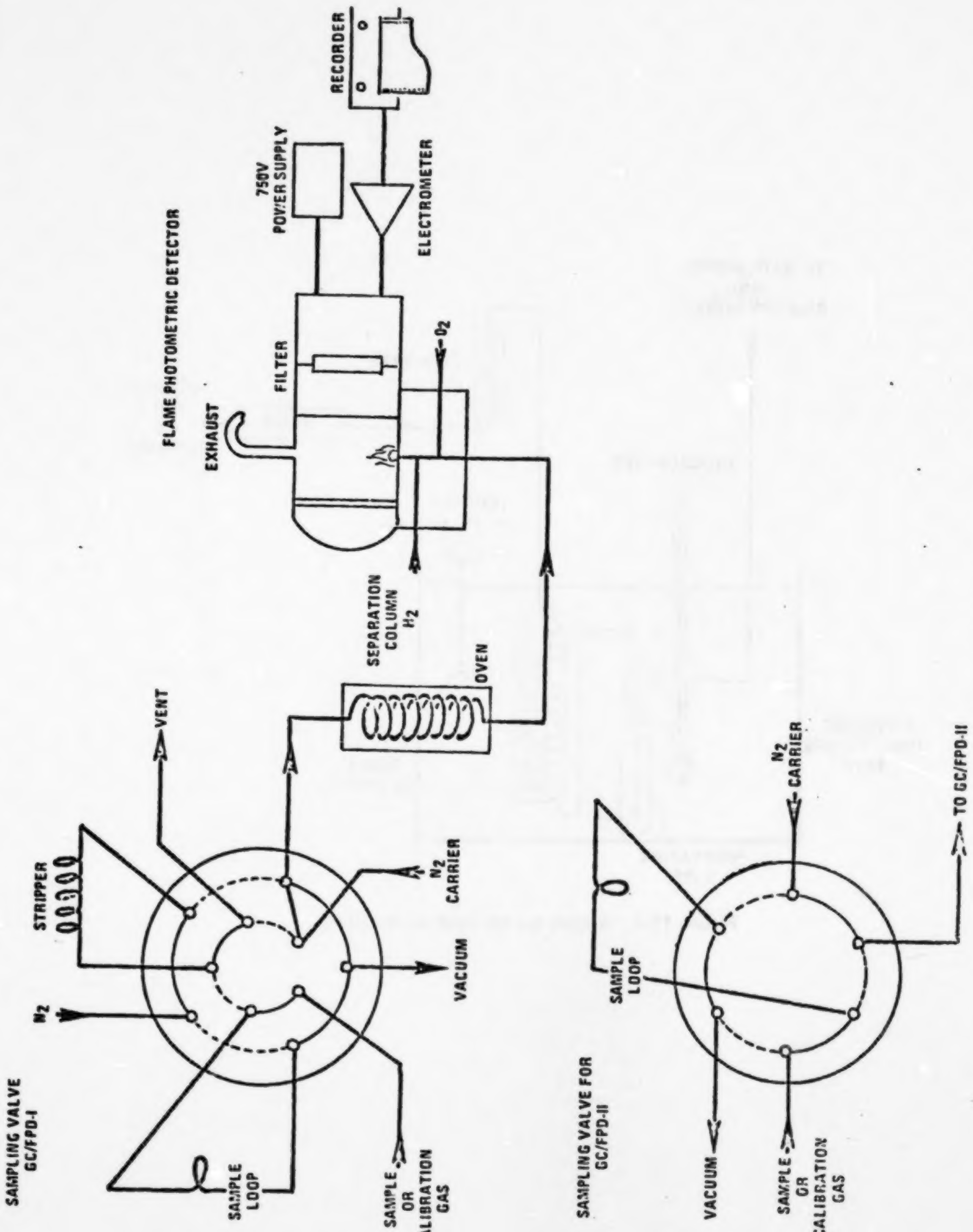

SAMPLING VALVE GC/FPD-I
N2
STRIPPER
VENT
SAMPLE LOOP
SAMPLE OR CALIBRATION GAS
VACUUM
N2 CARRIER
SEPARATION COLUMN
H2
OVEN
FLAME PHOTOMETRIC DETECTOR
EXHAUST
FILTER
O2
750V POWER SUPPLY
ELECTROMETER
RECORDER
SAMPLING VALVE FOR GC/FPD-II
SAMPLE LOOP
N2 CARRIER
TO GC/FPD-II
VACUUM
SAMPLE OR CALIBRATION GAS

Figure 16-3. Gas chromatographic-flame photometric analyzers.

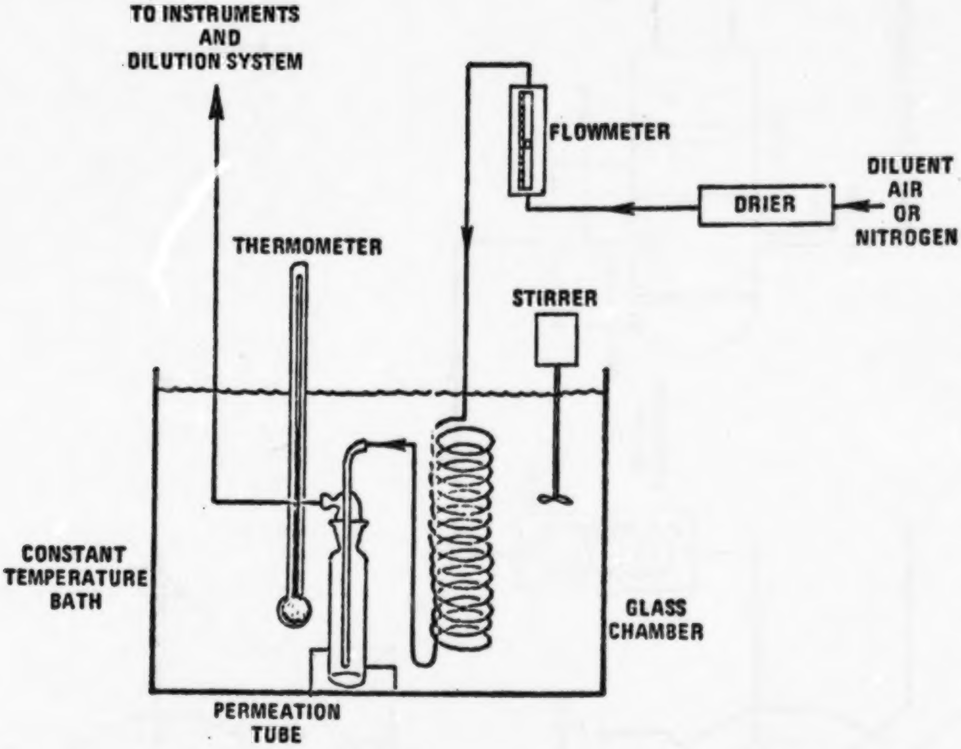

TO INSTRUMENTS
AND
DILUTION SYSTEM
FLOWMETER
DILUENT
AIR
OR
NITROGEN
DRIER
THERMOMETER
STIRRER
CONSTANT
TEMPERATURE
BATH
GLASS
CHAMBER
PERMEATION
TUBE

Figure 16-4. Apparatus for field calibration.

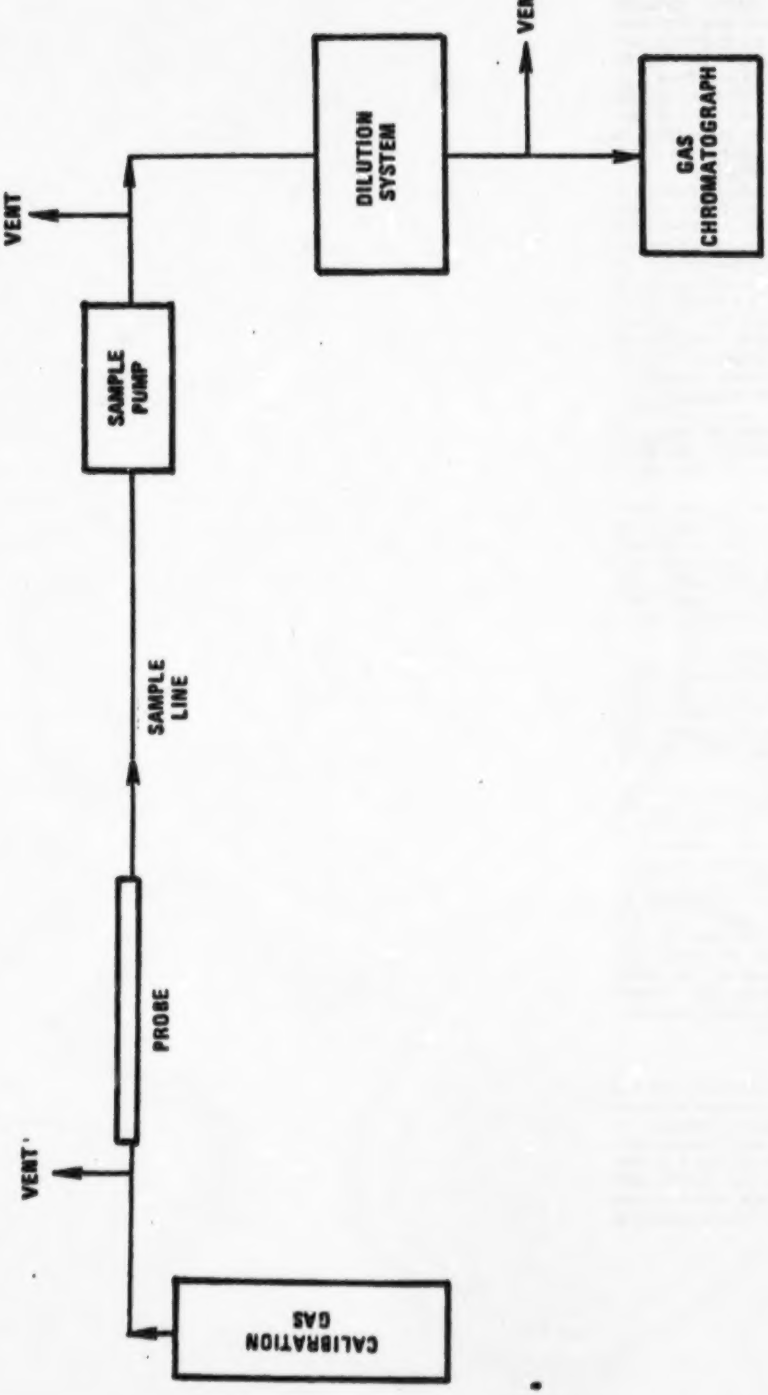

CALIBRATION GAS
VENT
PROBE
SAMPLE LINE
SAMPLE PUMP
VENT
DILUTION SYSTEM
VENT
GAS CHROMATOGRAPH

Figure 16- 5. Determination of sample line loss.

METHOD 17. DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES (IN-STACK FILTRATION METHOD)[82]

Introduction

Particulate matter is not an absolute quantity; rather, it is a function of temperature and pressure. Therefore, to prevent variability in particulate matter emission regulations and/or associated test methods, the temperature and pressure at which particulate matter is to be measured must be carefully defined. Of the two variables (i.e., temperature and pressure), temperature has the greater effect upon the amount of particulate matter in an effluent gas stream; in most stationary source categories, the effect of pressure appears to be negligible.

In method 5, 250° F is established as a nominal reference temperature. Thus, where Method 5 is specified in an applicable subpart of the standards, particulate matter is defined with respect to temperature. In order to maintain a collection temperature of 250° F, Method 5 employs a heated glass sample probe and a heated filter holder. This equipment is somewhat cumbersome and requires care in its operation. Therefore, where particulate matter concentrations (over the normal range of temperature associated with a specified source category) are known to be independent of temperature, it is desirable to eliminate the glass probe and heating systems, and sample at stack temperature.

This method describes an in-stack sampling system and sampling procedures for use in such cases. It is intended to be used only when specified by an applicable subpart of the standards, and only within the applicable temperature limits (if specified), or when otherwise approved by the Administrator.

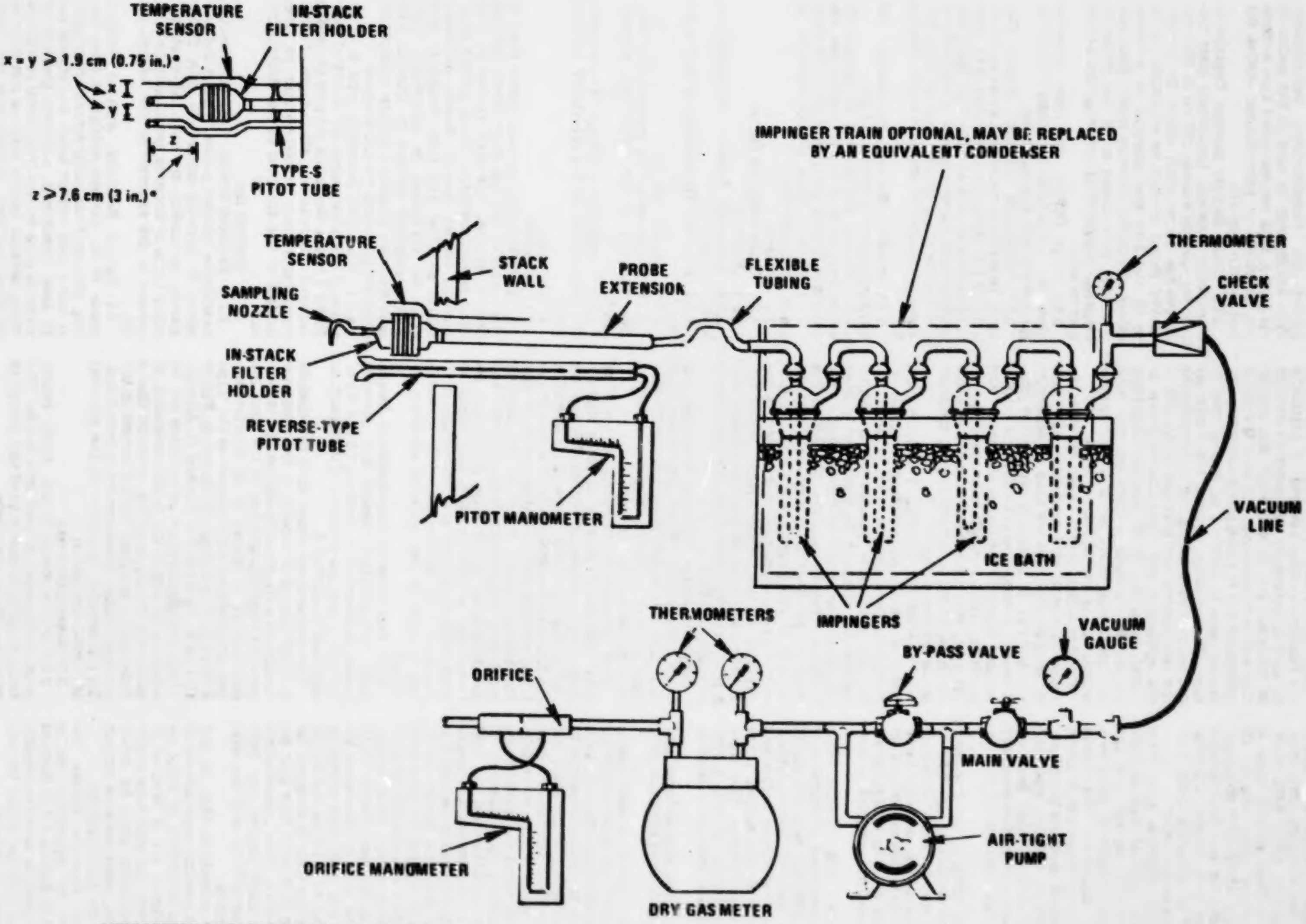
1. *Principle and Applicability.*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at stack temperature. The particulate mass is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method applies to the determination of particulate emissions from stationary sources for determining compliance with new source performance standards, only when specifically provided for in an applicable subpart of the standards. This method is not applicable to stacks that contain liquid droplets or are saturated with water vapor. In addition, this method shall not be used as written if the projected cross-sectional area of the probe extension-filter holder assembly covers more than 5 percent of the stack cross-sectional area (see Section 4.1.2).

2. *Apparatus.*

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 17-1. Construction details for many, but not all, of the train components are given in APTD-0581 (Citation 2 in Section 7); for changes from the APTD-0581 document and for allowable modifications to Figure 17-1, consult with the Administrator.


TEMPERATURE SENSOR
IN-STACK FILTER HOLDER
x = y > 1.9 cm (0.75 in.)*
x
y
z
z > 7.6 cm (3 in.)*
TYPE-S PITOT TUBE
IMPINGER TRAIN OPTIONAL, MAY BE REPLACED BY AN EQUIVALENT CONDENSER
TEMPERATURE SENSOR
STACK WALL
PROBE EXTENSION
FLEXIBLE TUBING
THERMOMETER
CHECK VALVE
SAMPLING NOZZLE
IN-STACK FILTER HOLDER
REVERSE-TYPE PITOT TUBE
PITOT MANOMETER
VACUUM LINE
ICE BATH
THERMOMETERS
IMPINGERS
VACUUM GAUGE
BY-PASS VALVE
ORIFICE
MAIN VALVE
AIR-TIGHT PUMP
ORIFICE MANOMETER
DRY GAS METER

*SUGGESTED (INTERFERENCE-FREE) SPACINGS

Figure 17-1. Particulate-Sampling Train, Equipped with In-Stack Filter.

The operating and maintenance procedures for many of the sampling train components are described in APTD-0576 (Citation 3 in Section 7). Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass, with sharp, tapered leading edge. The angle of taper shall be 030° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing. Other materials of construction may be used subject to the approval of the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (⅛ to ½ in)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in). Each nozzle shall be calibrated according to the procedures outlined in Section 5.1.

2.1.2 Filter Holder. The in-stack filter holder shall be constructed of borosilicate or quartz glass, or stainless steel; if a gasket is used, it shall be made of silicone rubber, Teflon, or stainless steel. Other holder and gasket materials may be used subject to the approval of the Administrator. The filter holder shall be designed to provide a positive seal against leakage from the outside or around the filter.

2.1.3 Probe Extension. Any suitable rigid probe extension may be used after the filter holder.

2.1.4 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator; the pitot tube shall be attached to the probe extension to allow constant monitoring of the stack gas velocity (see Figure 17-1). The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane during sampling (see Method 2, Figure 2-6b). It is recommended: (1) that the pitot tube have a known baseline coefficient, determined as outlined in Section 4 of Method 2; and (2) that this known coefficient be preserved by placing the pitot tube in an interference-free arrangement with respect to the sampling nozzle, filter holder, and temperature sensor (see Figure 17-1). Note that the 1.9 cm (0.75 in) free-space between the nozzle and pitot tube shown in Figure 17-1, is based on a 1.3 cm (0.5 in) ID nozzle. If the sampling train is designed for sampling at higher flow rates than that described in APTD-0581, thus necessitating the use of larger sized nozzles, the free-space shall be 1.9 cm (0.75 in) with the largest sized nozzle in place.

Source-sampling assemblies that do not meet the minimum spacing requirements of Figure 17-1 (or the equivalent of these requirements, e.g., Figure 2-7 of Method 2) may be used; however, the pitot tube coefficients of such assemblies shall be determined by calibration, using methods subject to the approval of the Administrator.

2.1.5 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.6 Condenser. It is recommended that the impinger system described in Method 5 be used to determine the moisture content of the stack gas. Alternatively, any system that allows measurement of both the water condensed and the moisture leaving the condenser, each to within 1 ml or 1 g, may be used. The moisture leaving the condenser can be measured either by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a silica gel trap with exit gases kept below 20° C (68° F) and determining the weight gain.

Flexible tubing may be used between the probe extension and condenser. If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.7 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 17-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.8 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.9 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3.

The temperature sensor shall be attached to either the pitot tube or to the probe extension, in a fixed configuration. If the temperature sensor is attached in the field; the sensor shall be placed in an interference-free arrangement with respect to the Type S pitot tube openings (as shown in Figure 17-1 or in Figure 2-7 of Method 2). Alternatively, the temperature sensor need not be attached to either the probe extension or pitot tube during sampling, provided that a difference of not more than 1 percent in the average velocity measurement is introduced. This alternative is subject to the approval of the Administrator.

2.2 Sample Recovery.

2.2.1 Probe Nozzle Brush. Nylon bristle brush with stainless steel wire handle. The brush shall be properly sized and shaped to brush out the probe nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples; glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethylene, to aid in sample recovery.

2.3 Analysis.

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 mg.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. *Reagents.*

3.1 Sampling.

3.1.1 Filters. The in-stack filters shall be glass mats or thimble fiber filters, without organic binders, and shall exhibit at least 99.95 percent efficiency (00.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles. The filter efficiency tests shall be conducted in accordance with ASTM standard method D 2986-71. Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2 Silica Gel. Indicating type, 6- to 16-mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Crushed Ice.

3.1.4 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone, reagent grade, 00.001 percent residue, in glass bottles. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers. Thus, acetone blanks shall be run prior to field use and only acetone with low blank values (00.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis.

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. *Procedure.*

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

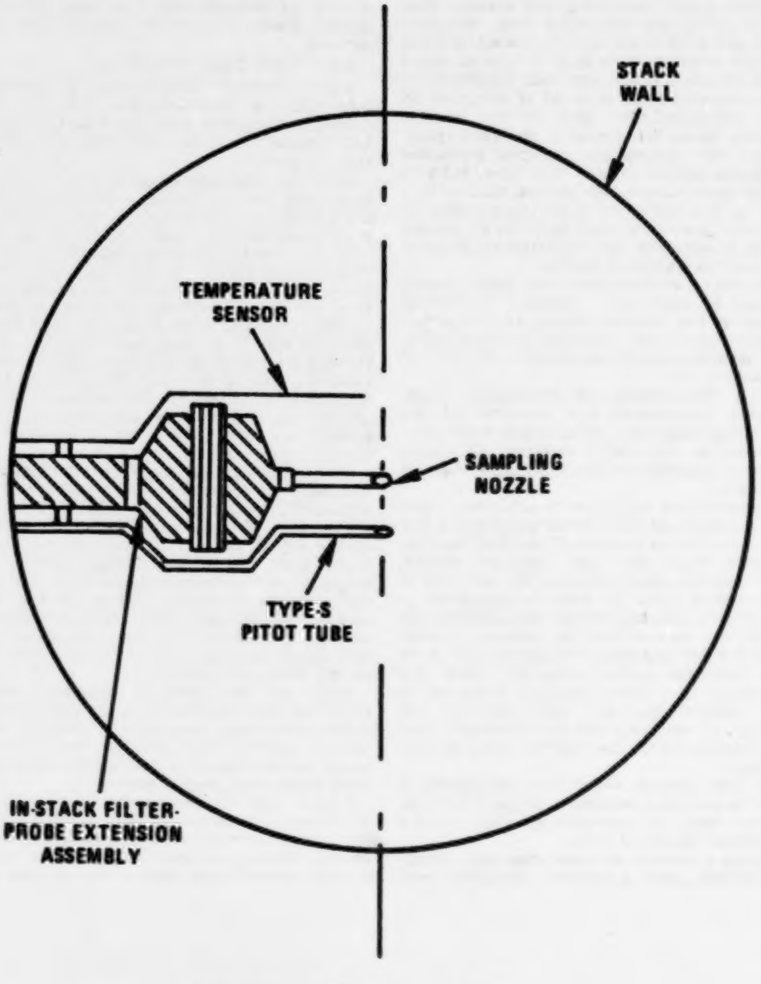
4.1.1 Pretest Preparation. All components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper size on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., 00.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Make a projected-area model of the probe extension-filter holder assembly, with the pitot tube face openings positioned along the centerline of the stack, as shown in Figure 17-2. Calculate the estimated cross-section blockage, as shown in Figure 17-2. If the blockage exceeds 5 percent of the duct cross sectional area, the tester has the following options: (1) a suitable out-of-stack filtration method may be used instead of in-stack filtration; or (2) a special in-stack arrangement, in which the sampling and velocity measurement sites are separate, may be used; for details concerning this approach, consult with the Administrator (see also Citation 10 in Section 7). Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particular sample run.



$$\text{ESTIMATED BLOCKAGE (\%)} = \left[\frac{\text{SHADED AREA}}{\text{DUCT AREA}}\right] \times 100$$

Figure 17-2. Projected-area model of cross-section blockage (approximate average for a sample traverse) caused by an in-stack filter holder-probe extension assembly.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a probe extension length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 minutes (or some greater time interval if specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

If impingers are used to condense stack gas moisture, prepare them as follows: place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

If some means other than impingers is used to condense moisture, prepare the condenser (and, if appropriate, silica gel for condenser outlet) for use.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as not to allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed. Mark the probe extension with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Assemble the train as in Figure 17-1, using a very light coat of silicone grease on all ground glass joints and greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Place crushed ice around the impingers.

4.1.4 Leak Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, plug the inlet to the probe nozzle with a material that will be able to withstand the stack temperature. Insert the filter holder into the stack and wait approximately 5 minutes (or longer, if necessary) to allow the system to come to equilibrium with the temperature of the stack gas stream. Turn on the pump and draw a vacuum of at least 380 mm Hg (15 in. Hg); note that a lower vacuum may be used, provided that it is not exceeded during the test. Determine the leakage rate. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m^3/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until the desired vacuum is reached. Do not reverse direction of by-pass valve. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak-check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe nozzle and immediately turn off the vacuum pump. This prevents water from being forced backward and keeps silica gel from being entrained backward.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-Test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain a sampling rate such that sampling is within 10 percent of true isokinetic, unless otherwise specified by the Administrator.

For each run, record the data required on the example data sheet shown in Figure 17-3. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted. Take other readings required by Figure 17-3 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

PLANT __________

LOCATION __________

OPERATOR __________

DATE __________

RUN NO. __________

SAMPLE BOX NO. __________

METER BOX NO. __________

METER Δ H@ __________

C FACTOR __________

PITOT TUBE COEFFICIENT, Cp __________

SCHEMATIC OF STACK CROSS SECTION

BAROMETRIC PRESSURE __________

ASSUMED MOISTURE, % __________

PROBE EXTENSION LENGTH, m(ft.) __________

NOZZLE IDENTIFICATION NO. __________

AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) __________

FILTER NO. __________

LEAK RATE, m^3/min, (cfm) __________

STATIC PRESSURE, mm Hg (in. Hg) __________

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_S), °C (°F)	VELOCITY HEAD (ΔP_S), mm H_2O (in. H_2O)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER, mm H_2O (in. H_2O)	GAS SAMPLE VOLUME, m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET, °C (°F)	OUTLET, °C (°F)	
TOTAL							Avg	Avg	
AVERAGE							Avg		

Figure 17-3. Particulate field data.

Clean the portholes prior to the test run to minimize the chance of sampling the deposited material. To begin sampling, remove the nozzle cap and verify that the pitot tube and probe extension are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment to the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85±0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29±4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomographs unless appropriate steps (see Citation 7 in Section 7) are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe extension assembly into the stack to prevent water from being forced backward. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe extension through the portholes, to minimize chance of extracting deposited material.

During the test run, take appropriate steps (e.g., adding crushed ice to the impinger ice bath) to maintain a temperature of less than 20° C (68° F) at the condenser outlet; this will prevent excessive moisture losses. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter holder assembly be used rather than attempting to change the filter itself. Before a new filter holder is installed, conduct a leak check, as outlined in Section 4.1.4.2. The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator. Note that when two or more trains are used, a separate analysis of the collected particulate from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case the particulate catches from the individual trains may be combined and a single analysis performed.

At the end of the sample run, turn off the pump, remove the probe extension assembly from the stack, and record the final dry gas meter reading. Perform a leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Section 3.1 of Method 2; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Section 6.11) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe extension assembly is removed from the stack at the end of the sampling period. Allow the assembly to cool.

When the assembly can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, forcing condenser water backward.

Before moving the sample train to the cleanup site, disconnect the filter holder-probe nozzle assembly from the probe extension; cap the open inlet of the probe extension. Be careful not to lose any condensate, if present. Remove the umbilical cord from the condenser outlet and cap the outlet. If a flexible line is used between the first impinger (or condenser) and the probe extension, disconnect the line at the probe extension and let any condensed water or liquid drain into the impingers or condenser. Disconnect the probe extension from the condenser; cap the probe extension outlet. After wiping off the silicone grease, cap off the condenser inlet. Ground glass stoppers, plastic caps, or serum caps (whichever are appropriate) may be used to close these openings.

Transfer both the filter holder-probe nozzle assembly and the condenser to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe nozzle or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, fitting, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone.

Brush and rinse with acetone the inside parts of the fitting in a similar way until no visible particles remain. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Rinse the brush with acetone and quantitatively collect these washings in the sample container. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints are wiped clean of silicone grease (if applicable), clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make final rinse of the brush and filter holder. After all acetone washings and particulate matter are collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents.

Container No. 3. if silica gel is used in the condenser system for mositure content determination, note the color of the gel to determine if it has been completely spent; make a notation of its condition. Transfer the silica gel back to its original container and seal. A funnel may make it easier to pour the silica gel without spilling, and a rubber policeman may be used as an aid in removing the silica gel. It is not necessary to remove the small amount of dust particles that may adhere to the walls and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for Container No. 3 under "Analysis."

Condenser Water. Treat the condenser or impinger water as follows: make a notation of any color or film in the liquid catch. Measure the liquid volume to within ±1 ml by using a graduated cylinder or, if a balance is available, determine the liquid weight to within ±0.5 g. Record the total volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas. Discard the liquid after measuring and recording the volume or weight.

4.3 Analysis. Record the data required on the example sheet shown in Figure 17-4. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at the average stack temperature or

105° C (220° F), whichever is less, for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at the average stack temperature or 105° C (220° F), whichever is less, for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Plant____________________________________

Date____________________________________

Run No.__________________________________

Filter No.________________________________

Amount liquid lost during transport ____________________

Acetone blank volume, ml__________________________

Acetone wash volume, ml__________________________

Acetone black concentration, mg/mg (equation 17-4) ______________

Acetone wash blank, mg (equation 17-5) __________________

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL	☒	☒	
	Less acetone blank		
	Weight of particulate matter		

	VOLUME OF LIQUID WATER COLLECTED		
	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g	
FINAL			
INITIAL			
LIQUID COLLECTED			
TOTAL VOLUME COLLECTED		g*	ml

* CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER (1g/ml).

$$\frac{\text{INCREASE, g}}{1\ \text{g/ml}} = \text{VOLUME WATER, ml}$$

Figure 17-4. Analytical data.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. This step may be conducted in the field. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

NOTE.—At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. *Calibration.* Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm ±(0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. If the pitot tube is placed in an interference-free arrangement with respect to the other probe assembly components, its baseline (isolated tube) coefficient shall be determined as outlined in Section 4 of Method 2. If the probe assembly is not interference-free, the pitot tube assembly coefficient shall be determined by calibration, using methods subject to the approval of the Administrator.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD-0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values.

Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m^3/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m^3/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD-0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

NOTE.—If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.5 Leak Check of Metering System Shown in Figure 17-1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 17-5). Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

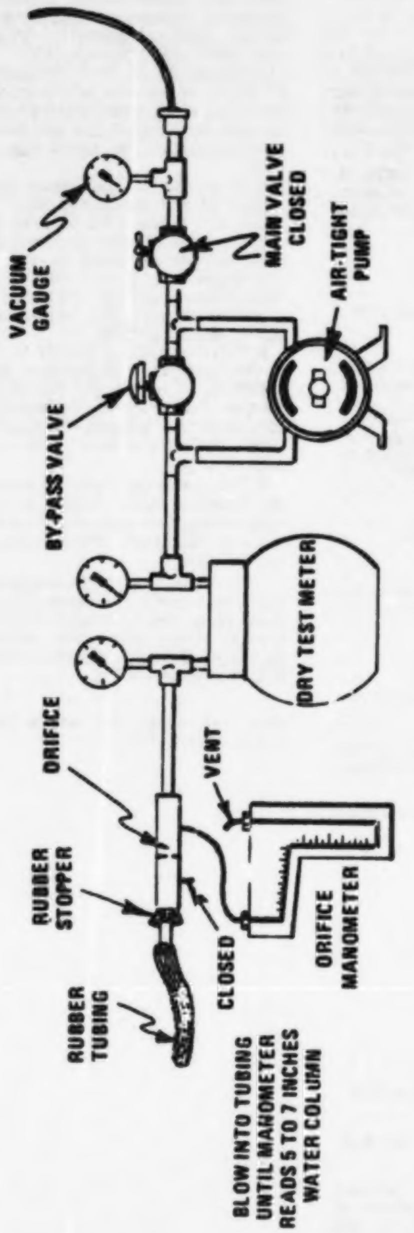


Figure 17-5. Leak check of meter box.

5.6 Barometer. Calibrate against a mercury barometer.

6. *Calculations.* Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

6.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m^2 (ft^2).
B_{ws} = Water vapor in the gas stream, proportion by volume.
C_a = Acetone blank residue concentration, mg/g.
c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).
I = Percent of isokinetic sampling.
L_a = Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.
L_i = Individual leakage rate observed during the leak check conducted prior to the "i^{th}" component change (i = 1, 2, 3 . . . n), m^3/min (cfm).
L_p = Leakage rate observed during the post-test leak check, m^3/min (cfm).
m_n = Total amount of particulate matter collected, mg.
M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).
m_a = Mass of residue of acetone after evaporation, mg.
P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R = Ideal gas constant, 0.06236 mm Hg-m^3/°K-g-mole (21.85 in. Hg-ft^3/°R-lb-mole).
T_m = Absolute average dry gas meter temperature (see Figure 17-3), °K (°R).
T_s = Absolute average stack gas temperature (see Figure 17-3), °K (°R).
T_{std} = Standard absolute temperature, 293°K (528°R).
V_a = Volume of acetone blank, ml.
V_{aw} = Volume of acetone used in wash, ml.
V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 17-4), ml.
V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).
v_s = Stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 17, m/sec (ft/sec).
W_a = Weight of residue in acetone wash, mg.
Y = Dry gas meter calibration coefficient.
ΔH = Average pressure differential across the orifice meter (see Figure 17-3), mm H_2O (in. H_2O).
ρ_a = Density of acetone, mg/ml (see label on bottle).
ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).
θ = Total sampling time, min.
θ_1 = Sampling time interval, from the beginning of a run until the first component change, min.
θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p—Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.
13.6—Specific gravity of mercury.
60—Sec/min.
100—Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 17-3).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 17-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right]$$

$$= K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 17-1

where:

K_1=0.3858° K/mm Hg for metric units; 17.64° R/in. Hg for English units.

NOTE.—Equation 17-1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 17-1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 17-1 with the expression:

$$[V_m - (L_p - L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 17-1 by the expression:

$$[V_m - (L_1 - L_a)\theta_1 - \sum_{i=2}^{n} (L_i - L_a)\theta_i - (L_p - L_a)\theta_p]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

$$V_{w(std)} = V_{1c}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2 V_{1c}$$

Equation 17-2

where:

K_2=0.001333 m³/ml for metric units; 0.04707 ft³/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}}$$

Equation 17-3

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a}$$

Equation 17-4

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a$$

Equation 17-5

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 17-4).

NOTE.—Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001\ g/mg)(m_n/V_{m(std)})$$

Equation 17-6

6.10 Conversion Factors:

From	To	Multiply by
scf	m³	0.02832
g/ft³	gr/ft³	15.43
g/ft³	lb/ft³	2.205×10⁻³
g/ft³	g/m³	35.31

6.11 Isokinetic Variation.

6.11.1 Calculation from Raw Data.

$$I = \frac{100\ T_s\ [K_3 V_{1c} + (V_m Y/T_m)(P_{bar} + \Delta H/13.6)]}{60\ \theta v_s P_s A_n}$$

Equation 17-7

where:

K_3=0.003454 mm Hg-m³/ml-°K for metric units; 0.002669 in. Hg-ft³/ml-°R for English units.

6.11.2 Calculation from Intermediate Values.

$$I = \frac{T_s V_{m(std)} P_{std}\ 100}{T_{std}\ v_s\ \theta\ A_n\ P_s\ 60\ (1-B_{ws})}$$

$$= K_4 \frac{T_s V_{m(std)}}{P_s\ v_s\ A_n\ \theta\ (1-B_{ws})}$$

Equation 17-8

where:

K_4=4.320 for metric units; 0.09450 for English units.

6.12 Acceptable Results. If 90 percent 010110 percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 in Section 7 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography.*

1. Addendum to Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. December 6, 1967.

2. Martin, Robert M., Construction Details of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0581. April, 1971.

3. Rom, Jerome J., Maintenance, Calibration, and Operation of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March, 1972.

4. Smith, W. S., R. T. Shigehara, and W. F. Todd. A Method of Interpreting Stack Sampling Data. Paper Presented at the 63rd Annual Meeting of the Air Pollution Control Association, St. Louis, Mo. June 14-19, 1970.

5. Smith, W. S., et al., Stack Gas Sampling Improved and Simplified with New Equipment. APCA Paper No. 67-119. 1967.

6. Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. 1967.

7. Shigehara, R. T., Adjustments in the EPA Nomograph for Different Pitot Tube Coefficients and Dry Molecular Weights. Stack Sampling News 2:4-11. October, 1974.

8. Vollaro, R. F., A Survey of Commercially Available Instrumentation for the Measurement of Low-Range Gas Velocities. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N.C. November, 1976 (unpublished paper).

9. Annual Book of ASTM Standards. Part 26. Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 617-622.

10. Vollaro, R. F., Recommended Procedure for Sample Traverses in Ducts Smaller than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N.C. November, 1976.

(Sec. 114. Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

Data Set No.	Time Begin	Time End	Date	Zero Reading	Zero Drift (ΔZero)	Span Reading	Span Drift (ΔSpan)	Calibration Drift (ΔSpan-ΔZero)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								

Zero Drift = [Mean Zero Drift* ________ + CI (Zero) ________] = ________.
Calibration Drift = [Mean Span Drift* ________ + CI (Span ________] = ________.
*Absolute Value.

Figure 3-1. Zero and Calibration Drift (2 Hour).

Date and Time	Zero Reading	Zero Drift (ΔZero)	Span Reading (After zero adjustment)	Calibration Drift (ΔSpan)

Zero Drift = [Mean Zero Drift* ________ + C.I. (Zero) ________]
= ________.

Calibration Drift = [Mean Span Drift* ________ + C.I. (Span) ________]
= ________.

* Absolute value

Figure 3-2. Zero and Calibration Drift (24-hour)

Data of Test __________

Span Gas Concentration __________ ppm

Analyzer Span Setting __________ ppm

Upscale
1. __________ seconds
2. __________ seconds
3. __________ seconds

Average upscale response __________ seconds

Downscale
1. __________ seconds
2. __________ seconds
3. __________ seconds

Average downscale response __________ seconds

System average response time (slower time) = __________ seconds

% deviation from slower system average response = $\frac{\text{average upscale minus average downscale}}{\text{slower time}} \times 100\%$

= __________.

Figure 3-3. Response

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

APPENDIX C—DETERMINATION OF EMISSION RATE CHANGE

1. *Introduction.*

1.1 The following method shall be used to determine whether a physical or operational change to an existing facility resulted in an increase in the emission rate to the atmosphere. The method used is the Student's *t* test, commonly used to make inferences from small samples.

2. *Data.*

2.1 Each emission test shall consist of *n* runs (usually three) which produce *n* emission rates. Thus two sets of emission rates are generated, one before and one after the change, the two sets being of equal size.

2.2 When using manual emission tests, except as provided in § 60.8(b) of this part, the reference methods of Appendix A to this part shall be used in accordance with the procedures specified in the applicable subpart both before and after the change to obtain the data.

2.3 When using continuous monitors, the facility shall be operated as if a manual emission test were being performed. Valid data using the averaging time which would be required if a manual emission test were being conducted shall be used.

3. *Procedure.*

3.1 Subscripts a and b denote prechange and postchange respectively.

3.2 Calculate the arithmetic mean emission rate, $\bar{E}$, for each set of data using Equation 1.

$$\bar{E}=\frac{\sum\limits_{i=1}^{n} E_i}{n}=\frac{E_1+E_2\ldots+E_n}{n} \qquad (1)$$

where:
E_i=Emission rate for the *i* th run.
n=number of runs

3.3 Calculate the sample variance, S^2, for each set of data using Equation 2.

$$S^2=\frac{\sum\limits_{i=1}^{n}(E_i-\bar{E})^2}{n-1}=\frac{\sum\limits_{i=1}^{n}E_i^2-\left(\sum\limits_{i=1}^{n}E_i\right)^2\Big/n}{n-1} \qquad (2)$$

3.4 Calculate the pooled estimate, S_p, using Equation 3.

$$S_p=\left[\frac{(n_a-1)\,S_a^2+(n_b-1)\,S_b^2}{n_a+n_b-2}\right]^{1/2} \qquad (3)$$

3.5 Calculate the test statistic, *t*, using Equation 4.

$$t=\frac{\bar{E}_b-\bar{E}_a}{S_p\left[\frac{1}{n_a}+\frac{1}{n_b}\right]^{1/2}} \qquad (4)$$

4. *Results.*

4.1 If $\bar{E}_b>\bar{E}_a$ and $t>t'$, where t' is the critical value of *t* obtained from Table 1, then with 95% confidence the difference between $\bar{E}_b$ and $\bar{E}_a$ is significant, and an increase in emission rate to the atmosphere has occurred.

TABLE 1

Degree of freedom (n_a+n_b-2):	t' (95 percent confidence level)
2	2.920
3	2.353
4	2.132
5	2.015
6	1.943
7	1.895
8	1.860

For greater than 8 degrees of freedom, see any standard statistical handbook or text.

5.1 Assume the two performance tests produced the following set of data:

Test a:	Test b
Run 1. 100	115
Run 2. 95	120
Run 3. 110	125

5.2 Using Equation 1—

$$\bar{E}_a=\frac{100+95+110}{3}=102$$

$$\bar{E}_b=\frac{115+120+125}{3}=120$$

5.3 Using Equation 2—

$$S_a^2=\frac{(100-102)^2+(95-102)^2+(110-102)^2}{3-1}=58.5$$

$$S_b^2=\frac{(115-120)^2+(120-120)^2+(125-120)^2}{3-1}=25$$

5.4 Using Equation 3—

$$S_p=\left[\frac{(3-1)\,(58.5)+(3-1)\,(25)}{3+3-2}\right]^{1/2}=6.46$$

5.5 Using Equation 4—

$$t=\frac{120-102}{6.46\left[\frac{1}{3}+\frac{1}{3}\right]^{1/2}}=3.412$$

5.6 Since $(n_1+n_2-2)=4$, $t'=2.132$ (from Table 1). Thus since $t>t'$ the difference in the values of $\bar{E}_a$ and $\bar{E}_b$ is significant, and there has been an increase in emission rate to the atmosphere.

6. *Continuous Monitoring Data.*

6.1 Hourly averages from continuous monitoring devices, where available, should be used as data points and the above procedure followed.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

APPENDIX D—REQUIRED EMISSION INVENTORY INFORMATION

(a) Completed NEDS point source form(s) for the entire plant containing the designated facility, including information on the applicable criteria pollutants. If data concerning the plant are already in NEDS, only that information must be submitted which is necessary to update the existing NEDS record for that plant. Plant and point identification codes for NEDS records shall correspond to those previously assigned in NEDS; for plants not in NEDS, these codes shall be obtained from the appropriate Regional Office.

(b) Accompanying the basic NEDS information shall be the following information on each designated facility:

(1) The state and county identification codes, as well as the complete plant and point identification codes of the designated facility in NEDS. (The codes are needed to match these data with the NEDS data.)

(2) A description of the designated facility including, where appropriate:

(i) Process name.

(ii) Description and quantity of each product (maximum per hour and average per year).

(iii) Description and quantity of raw materials handled for each product (maximum per hour and average per year).

(iv) Types of fuels burned, quantities and characteristics (maximum and average quantities per hour, average per year).

(v) Description and quantity of solid wastes generated (per year) and method of disposal.

(3) A description of the air pollution control equipment in use or proposed to control the designated pollutant, including:

(i) Verbal description of equipment.

(ii) Optimum control efficiency, in percent. This shall be a combined efficiency when more than one device operate in series. The method of control efficiency determination shall be indicated (e.g., design efficiency, measured efficiency, estimated efficiency).

(iii) Annual average control efficiency, in percent, taking into account control equipment down time. This shall be a combined efficiency when more than one device operate in series.

(4) An estimate of the designated pollutant emissions from the designated facility (maximum per hour and average per year). The method of emission determination shall also be specified (e.g., stack test, material balance. emission factor).

(Sec. 114. Clean Air Act is amended (42 U.S.C. 7414)).$^{08.83}$

56. 42 FR 4124, 1/24/77 - Delegation of Authority to the State of South Carolina. 158

42 FR 4863, 1/26/77 - Proposed Revisions to Standards of Performance for Sewage Sludge Incinerators.

42 FR 4883, 1/26/77 - Receipt of Application and Approval of Alternative Test Method. 158

42 FR 5121, 1/27/77 - Notice of Study to Review Standards for Fossil Fuel-Fired Steam Generators; SO_2 Emissions.

57. 42 FR 5936, 1/31/77 - Revisions to Emission Monitoring Requirements and to Reference Methods Promulgated. 159

58. 42 FR 6812, 2/4/77 - Delegation of Authority to City of Philadelphia. 161

42 FR 10019, 2/18/77 - Proposed Standards for Sewage Treatment Plants; Correction.

42 FR 12130, 3/2/77 - Proposed Revision to Standards of Performance for Iron & Steel Plants; Basic Oxygen Process Furnaces.

42 FR 13566, 3/11/77 - Proposed Standards of Performance for Grain Elevators; Extension of Comment Period.

59. 42 FR 16777, 3/30/77 - Correction of Region V Address and Delegation of Authority to the State of Wisconsin. 161

42 FR 18884, 4/11/77 - Notice of Public Hearing on Coal-Fired Steam Generators SO_2 Emissions.

42 FR 22506, 5/3/77 - Proposed Standards of Performance for Lime Manufacturing Plants.

60. 42 FR 26205, 5/23/77 - Revision of Compliance with Standards and Maintenance Requirements. 162

42 FR 26222, 5/23/77 - Proposed Revision of Reference Method 11.

42 FR 32264, 6/24/77 - Suspension of Proposed Standards of Performance for Grain Elevators.

61. 42 FR 32426, 6/24/77 - Revisions to Standards of Performance for Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators Promulgated. 162

62. 42 FR 37000, 7/19/77 - Revision and Reorganization of the Units and Abbreviations. 164

42 FR 37213, 7/20/77 - Notice of Intent to Develop Standards of Performance for Glass Melting Furnaces.

63. 42 FR 37386, 7/21/77 - Delegation of Authority to the State of New Jersey. 165

64. 42 FR 37936, 7/25/77 - Applicability Dates Incorporated into Existing Regulations. 165

65. 42 FR 38178, 7/27/77 - Standards of Performance for Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators and Units and Measures; Corrections. 168

66. 42 FR 39389, 8/4/77 - Standards of Performance for Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators, Correction. 168

67. 42 FR 41122, 8/15/77 - Amendments to Subpart D; Correction. 168

68. 42 FR 41424, 8/17/77 - Authority Citations; Revision 169

69. 42 FR 41754, 8/18/77 - Revision to Reference Methods 1-8 Promulgated. 170

70. 42 FR 44544, 9/6/77 - Delegation of Authority to the State of Montana. 206

71. 42 FR 44812, 9/7/77 - Standards of Performance, Applicability Dates; Correction. 206

42 FR 45705, 9/12/77 - Notice of Delegation of Authority to the State of Indiana.

72. 42 FR 46304, 9/15/77 - Delegation of Authority to the State of Wyoming. 207

42 FR 53782, 10/3/77 - Proposed Standards of Performance for Stationary Gas Turbines.

73. 42 FR 55796, 10/18/77 - Emission Guidelines for Sulfuric Acid Mist Promulgated. 208

74. 42 FR 57125, 11/1/77 - Amendments to General Provisions and Copper Smelter Standards Promulgated. 209

75. 42 FR 58520, 11/10/77 - Amendment to Sewage Sludge Incinerators Promulgated. 211

76. 42 FR 61537, 12/5/77 - Opacity Provisions for Fossil-Fuel-Fired Steam Generators Promulgated. 212

42 FR 61541, 12/5/77 - Opacity Standards for Fossil-Fuel-Fired Steam Generators: Final EPA Response to Remand.

77. 42 FR 62137, 12/9/77 - Delegation of Authority to the Commonwealth of Puerto Rico. 214

42 FR 62164, 12/9/77 - Proposed Standards for Stationary Gas Turbines; Extension of Comment Period.

78. 43 FR 9, 1/3/78 - Delegation of Authority to the State of Minnesota. 214

79. 43 FR 1494, 1/10/78 - Revision of Reference Method II Promulgated. 215

80. 43 FR 3360, 1/25/78 - Delegation of Authority to the Commonwealth of Kentucky. 219

81. 43 FR 6770, 2/16/78 - Delegation of Authority to the State of Delaware. 220

82. 43 FR 7568, 2/23/78 - Standards of Performance Promulgated for Kraft Pulp Mills. 221

83. 43 FR 8800, 3/3/78 - Revision of Authority Citations. 249

84. 43 FR 9276, 3/7/78 - Standards of Performance Promulgated for Lignite-Fired Steam Generators. 250

85. 43 FR 9452, 3/7/78 - Standards of Performance Promulgated for Lime Manufacturing Plants. 253

86. 43 FR 10866, 3/15/78 - Standards of Performance Promulgated for Petroleum Refinery Claus Sulfur Recovery Plants. 255

87. 43 FR 11984, 3/23/78 - Corrections and Amendments to Reference Methods 1-8. 262

43 FR 14602, 4/6/78 - Notice of Regulatory Agenda.

88. 43 FR 15600, 4/13/78 - Standards of Performance Promulgated for Basic Oxygen Process Furnaces: Opacity Standard. 265

89. 43 FR 20986, 5/16/78 - Delegation of Authority to State/Local Air Pollution Control Agencies in Arizona, California, and Nevada. 268

43 FR 21616, 5/18/78 - Proposed Standards of Performance for Storage Vessels for Petroleum Liquids.

43 FR 22221, 5/24/78 - Correction to Proposed Standards of Performance for Storage Vessels for Petroleum Liquids.

90. 43 FR 34340, 8/3/78 - Standards of Performance Promulgated for Grain Elevators. 269

43 FR 34349, 8/3/78 - Reinstatement of Proposed Standards for Grain Elevators.

91. 43 FR 34784, 8/7/78 - Amendments to Standards of Performance for Kraft Pulp Mills and Reference Method 16. 277

43 FR 34892, 8/7/78 - Proposed Regulatory Revisions Air Quality Surveillance and Data Reporting.

43 FR 38872, 8/31/78 - Proposed Priority List for Standards of Performance for New Stationary Sources.

43 FR 42154, 9/19/78 - Proposed Standards of Performance for Electric Utility Steam Generating Units and Announcement of Public Hearing on Proposed Standards.

43 FR 42186, 9/19/78 - Proposed Standards of Performance for Primary Aluminum Industry.

92. 43 FR 47692, 10/16/78 - Delegation of Authority to the State of Rhode Island. 278

43 FR 54959, 11/24/78 - Public Hearing on Proposed Standards for Electric Utility Steam Generating Units.

43 FR 55258, 11/27/78 - Electric Utility Steam Generating Units; Correction and Additional Information.

43 FR 57834, 12/8/78 - Electric Utility Steam Generating Units; Additional Information.

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 790-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Wyoming

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This rule will change the address to which reports and applications must be sent by owners and operators of new and modified sources in the State of Wyoming. The address change is the result of delegation of authority to the State of Wyoming for New Source Performance Standards (40 CFR Part 60).

ADDRESS: Any questions or comments should be sent to Director, Enforcement Division, Environmental Protection Agency, 1860 Lincoln Street, Denver, Colo. 80295.

FOR FURTHER INFORMATION CONTACT:

Mr. Irwin L. Dickstein, 303-837-3868.

SUPPLEMENTARY INFORMATION: The amendments below institute certain address changes for reports and applications required from operators of new and modified sources. EPA has delegated to the State of Wyoming authority to review new and modified sources. The delegated authority includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources.

A notice announcing the delegation of authority is published today in the FEDERAL REGISTER (Notices Section). The amendments now provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent to the Air Quality Division of the Wyoming Department of Environmental Quality instead of EPA's Region VIII.

The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on August 2, 1977, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

(Sec. 111, Clean Air Act, as amended (42 U.S.C. 1857, 1857c-5, 6, 7, 1857g).)

Dated: August 25, 1977.

JOHN A. GREEN,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (ZZ) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(ZZ) State of Wyoming, Air Quality Division of the Department of Environmental Quality, Hathaway Building, Cheyenne, Wyo. 82002.

* * * * *

[FR Doc.77-26905 Filed 9-14-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 179
THURSDAY, SEPTEMBER 15, 1977

73

Title 40—Protection of Environment

[FRL 770-7]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Emission Guideline for Sulfuric Acid Mist

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action establishes emission guidelines and times for compliance for control of sulfuric acid mist emissions from existing sulfuric acid plants. Standards of performance have been issued for emissions of sulfuric acid mist, a designated pollutant, from new, modified, and reconstructed sulfuric acid plants. The Clean Air Act requires States to control emissions of designated pollutants from existing sources, and this rulemaking initiates the States' action and provides them guidelines for what will be acceptable by EPA.

DATES: State plans providing for the control of sulfuric acid mist from existing plants are due for submission to the Administrator on July 18, 1978. The Administrator has four months from the date required for submission of the plans, or until November 18, 1978, to take action to approve or disapprove the plan or portions of it.

ADDRESSES: Copies of the final guideline document are available by writing to the EPA Public Information Center (PM-215), 401 M Street SW., Washington, D.C. 20460. "Final Guidance Document: Control of Sulfuric Acid Mist Emissions From Existing Sulfuric Acid Production Units," June 1977, should be specified when requesting the document. A summary of the comments and EPA's responses may be obtained at the same address. Copies of the comment letters responding to the proposed rulemaking published in the FEDERAL REGISTER on November 4, 1976 (41 FR 48706) are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711; telephone: 919-541-5271.

SUPPLEMENTARY INFORMATION: On November 4, 1976 (41 FR 48706) EPA proposed an emission guideline for sulfuric acid mist emissions from existing sulfuric acid plants and announced the availability of a draft guideline document for public comment. A discussion of the background and comments received follows:

BACKGROUND

Section 111(d) of the Clean Air Act requires that "designated" pollutants controlled under standards of performance for new stationary sources by section 111(b) of the Act must also be controlled at existing sources in the same source category. New source standards of performance for sulfuric acid mist were promulgated December 23, 1971 (36 FR 24876). Sulfuric acid mist is considered a designated pollutant; therefore, it must be controlled under the provisions of section 111(d).

As a step toward implementing the requirements of section 111(d), Subpart B of Part 60, entitled "State Plans for the Control of Certain Pollutants From Existing Facilities," was published on November 17, 1975 (40 FR 53340).

Subpart B provides that once a standard of performance for the control of a designated pollutant from a new source category is promulgated, the Administrator will then publish a draft emission guideline and guideline document applicable to the control of the same pollutant from designated (existing) facilities. For health-related pollutants, the emission guideline will be proposed and subsequently be promulgated while emission guidelines for welfare-related pollutants will appear only in the applicable guideline document. Sulfuric acid mist is considered a health-related pollutant; therefore, the proposed emission guideline and the announcement that the draft guideline document was available for public inspection and comment appeared in the FEDERAL REGISTER November 4, 1976.

Subpart B also provides nine months for the States to develop and submit plans for control of the designated pollutant from the date that the notice of availability of a final guideline is published; thus, the States will have nine months from this date to develop their plans for the control of sulfuric acid mist at designated facilities within the State.

Another provision of Subpart B is that which provides the Administrator the option of either approving or disapproving the State submitted plan or portions of it within four months after the date required for submission. If the plan or a portion of it is disapproved, the Administrator is required to promulgate a new plan or a replacement of the inadequate portions of the plan. These and related provisions of Subpart B are essentially patterned after section 110 of the Act and 40 CFR Part 51 which sets forth the requirements for adoption and submittal of State implementation plans under section 110 of the Act.

COMMENTS AND RESPONSES

During the 60-day comment period following the publication of the proposed emission guidelines on November 4, 1976, eleven comment letters were received; four from State pollution control agencies, five from industry and two from other government agencies. None of the comments warranted a change in the emission guideline nor did any comments justify any significant changes in the guideline document.

One commenter believed that sulfuric acid mist is included within the definition of sulfur oxides as contained in the Air Quality Criteria for Sulfur Oxides; therefore, it is subject to control as a criteria pollutant under State implementation plans, section 110 of the Clean Act, and not as a designated pollutant under section 111(d) of the Act. EPA does not agree with this comment. Sulfuric acid mist is only one of a number of related compounds noted in the criteria document defining sulfur oxides. Sulfuric acid mist is not listed and regulated in and of itself. In addition, although some designated pollutants controlled under section 111(d) may occur in particulate as well as gaseous form and thus may be controlled to some degree under State implementation plan regulations requiring control of particulate matter, specific rather than incidental control of such pollutants is required under section 111(d).

Several commenters were concerned that the emission guideline was not based on the health and welfare effects of sulfuric acid mist or on such other factors as plant site location and the hazard of cumulative impacts where emissions from other sources interacted. Another commenter noted that since the toxicological effects of exposure to sulfuric acid mist are a function of concentration and time, a daily maximum time-weighted average concentration limitation should be considered.

These comments appear to be based on a misunderstanding of the intent and purpose of section 111(d) of the Act. In the preamble to the section 111(d) procedural regulation (40 FR 53340), it is stated that section 111(d) requires emission controls based on the general principle of the application of the best adequately demonstrated control technology, considering costs, rather than controls based directly on health or welfare effects or on other factors such as those mentioned in the comments. Section 111(b)(1)(A) of the Act requires the Administrator to list categories of sources once it is determined that they may contribute to the endangerment of public health or welfare. While this is a prerequisite for the development of standards under section 111(d), the emission guideline is technology-based rather than tied specifically to protection of health or welfare. The States, in developing regulations for the control of sulfuric acid mist, have the prerogative under 40 CFR 60.24 (f) and (g) to develop standards which may be based on health or welfare considerations or on any other relevant factors.

Some of the comments addressed the stringency of the emission guideline. One commenter considered the emission guideline inflexible to the point where its application will be too stringent in some areas and inadequate in others. Another commenter thought the guideline document indicated that facilities using elemental sulfur as feedstock can meet more rigid emission standards and that the emission guidelines should include more stringent standards for these facilities.

EPA has provided a great deal of flexibility in developing emission standards for the control of designated pollutants under Subpart B of Part 60. Specifically, 40 CFR 60.24(b) provides that nothing under Subpart B precludes any State from adopting or enforcing more stringent emission standards than those specified in the guideline document. On the other hand, 40 CFR Part 60.24(f) provides that States, "on a case-by-case basis for particular designated facilities, or classes of facilities * * * may provide for the application of less stringent emission standards than those otherwise required * * *" provided certain conditions are demonstrated by the State. The conditions include unreasonable cost of control resulting from plant age, location or basic process design, physical impossibility of installing necessary control equipment, and other factors specific to the facility that make the application of a less stringent standard significantly more reasonable. To include more stringent standards for facilities using elemental sulfur as feedstock would cause an unacceptable economic burden for those sources which have already installed efficient emission control equipment to meet a State regulation. To require these sources to retrofit additional emission control equipment to meet a more stringent standard would be inequitable.

MISCELLANEOUS

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Order 11821 and 11949 and OMB Circular A-107.

Dated: September 22, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I of Title 40 of the Code of Federal Regulations is amended by adding Subpart C as follows:

Subpart C—Emission Guidelines and Compliance Times

Sec.
60.30 Scope.
60.31 Definitions.
60.32 Designated facilities.
60.33 Emission guidelines.
60.34 Compliance times.

AUTHORITY: Sections 111(d), 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c-6 and 1857g(a)), and additional authority as noted below.

Subpart C—Emission Guidelines and Compliance Times

§ 60.30 Scope.

This subpart contains emission guidelines and compliance times for the control of certain designated pollutants from certain designated facilities in accordance with section 111(d) of the Act and Subpart B.

§ 60.31 Definitions.

Terms used but not defined in this subpart have the meaning given them in the Act and in Subparts A and B of this part.

§ 60.32 Designated facilities.

(a) Sulfuric acid production units. The designated facility to which §§ 60.33 (a) and 60.34(a) apply is each existing "sulfuric acid production unit" as defined in § 60.81(a) of Subpart H.

§ 60.33 Emission guidelines.

(a) Sulfuric acid production units. The emission guideline for designated facilities is 0.25 gram sulfuric acid mist (as measured by Reference Method 8, of Appendix A) per kilogram of sulfuric acid produced (0.5 lb/ton), the production being expressed as 100 percent H_2SO_4.

§ 60.34 Compliance times.

(a) Sulfuric acid production units. Planning, awarding of contracts, and installation of equipment capable of attaining the level of the emission guideline established under § 60.33(a) can be accomplished within 17 months after the effective date of a State emission standard for sulfuric acid mist.

[FR Doc.77-30406 Filed 10-17-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 201

TUESDAY, OCTOBER 18, 1977

74

[FRL 783-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to General Provisions and Copper Smelter Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule clarifies that excess emissions during periods of startup, shutdown, and malfunction are not considered a violation of a standard. This rule also clarifies that excess emissions for no more than 1.5 percent of the time during a quarter will not be considered indicative of a potential violation of the new source performance standard for primary copper smelters provided the affected facility and the air pollution control equipment are maintained and operated consistent with good air pollution control practice.

EFFECTIVE DATE: November 1, 1977.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

BACKGROUND

EPA promulgated standards of performance for primary copper, zinc and lead smelters on January 15, 1976. On March 5, 1976, Kennecott Copper Corporation filed a petition with the United States Court of Appeals for the District of Columbia Circuit requesting that EPA reconsider the standards for copper smelters. EPA proposed to make two clarifying amendments to the standards, and Kennecott agreed to withdraw its court challenge providing these amendments were made. The amendments being made are in response to the following two issues raised in the Kennecott court appeal:

(1) The standards of performance fail to provide for excessive emissions during periods of startup, shutdown, and malfunction.

(2) The standards of performance prescribe averaging times too short to accommodate the normal fluctuations in sulfur dioxide emissions inherent in smelting operations.

EXCESS EMISSIONS DURING STARTUP, SHUTDOWN AND MALFUNCTION

For all sources covered under 40 CFR Part 60, compliance with numerical emission limits must be determined through performance tests. 40 CFR 60.8(c) exempts periods of startup, shutdown, and malfunction from performance tests. By implication this means compliance with numerical emission limits cannot be determined during periods of startup, shutdown, and malfunction. EPA and Kennecott have agreed that for clarification purposes this should be specifically stated in the regulation. Therefore, an amendment to this effect is being made in 40 CFR 60.8(c).

This exemption from compliance with numerical emission limits during startup, shutdown and malfunction, however, does not exempt the owner or operator from compliance with the requirements of 40 CFR 60.11(d) which says: "At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions."

AVERAGING TIMES

Kennecott alleged that a six-hour averaging time is not long enough to average out periods of excessive emissions of sulfur dioxide which normally occur at smelters equipped with best control technology. According to Kennecott, the six-hour averaging period simply does not mask emission variations caused by normal fluctuations in gas strengths and volumes.

A performance test to determine compliance with the numerical emission limit included in the standard of performance consists of the arithmetic average of three consecutive six-hour emission tests. EPA's analysis of the emission data presented in the background document ("Background Information for New Source Performance Standards: Primary Copper, Zinc, and Lead Smelters," October 1974) supporting the standards of performance for copper smelters indicates that the possibility of a performance test exceeding the standard of performance under normal conditions is extremely low, less than 0.15 percent. This same analysis, however, indicates that the possibility of emissions averaged over a single six-hour period exceeding the numerical emission limit included in the standard of performance during normal operation is about 1.5 percent. To reconcile this situation with the excess emission reporting requirements, which currently require all six-hour periods in excess of the level of the sulfur dioxide standard to be reported as excess emissions, 40 CFR 60.165 is being amended to provide that if emissions exceed the level of the standard for no more than 1.5 percent of the six-hour averaging periods during a quarter, they will not be considered indicative of potential violation of 40 CFR 60.11(d); i.e., indicative of improper maintenance or operation. This exemption applies, however, only if the owner or operator maintains and operates the affected facility and air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions during these periods. This ensures that the control equipment will be operated and emissions will be minimized during this time. Excess emissions during periods of startup, shutdown, and malfunction are not considered part of the 1.5 percent.

MISCELLANEOUS

The Administrator finds that good cause exists for omitting prior notice and public comment on these amendments and for making them immediately effective because they simply clarify the existing regulations and impose no additional substantive requirements.

NOTE.—The EPA has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Statement under Executive Orders 11821 and 11949, and OMB Circular R–107.

Dated: October 25, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.8, paragraph (c) is amended to read as follows:

§ 60.8 Performance tests.

* * * * *

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

* * * * *

2. In § 60.165, paragraph (d)(2) is amended to read as follows:

§ 60.165 Monitoring of operations.

* * * * *

(d) * * *

(2) Sulfur dioxide. All six-hour periods during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under § 60.163, exceed the level of the standard. The Administrator will not consider emissions in excess of the level of the standard for less than or equal to 1.5 percent of the six-hour periods during the quarter as indicative of a potential violation of § 60.11(d) provided the affected facility, including air pollution control equipment, is maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions during these periods. Emissions in excess of the level of the standard during periods of startup, shutdown, and malfunction are not to be included within the 1.5 percent.

(Secs. 111, 114, and 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c–6, 1857c–9, 1857g(a)).)

[FR Doc.77–31506 Filed 10–31–77;8:45 am]

75 [FRL 781-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendment to Subpart O: Sewage Sludge Incinerators

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This rule revises the applicability of the standard of performance for sewage sludge incinerators to cover any incinerator that burns wastes containing more than 10 percent sewage sludge (dry basis) produced by municipal sewage treatment plants, or charges more than 1000 kg (2205 lb) per day municipal sewage sludge (dry basis). The State of Alaska requested that EPA revise the standard because incinerators small enough to meet the needs of small communities in Alaska and comply with the particulate matter standard are too costly, and land disposal is not feasible in areas with permafrost and high water tables. The intended effect of the revision is to exempt from the standard small incinerators for the combined disposal of municipal wastes and sewage sludge when land disposal, which is normally a cheaper and preferable alternative, is infeasible due to permafrost, high water tables, or other conditions.

DATES: This amendment is effective November 10, 1977, as required by § 111(b)(1)(B) of the Clean Air Act as amended.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On January 26, 1977 (42 FR 4863), EPA published a proposed amendment to Subpart 0 of 40 CFR Part 60. An error in that proposal necessitated a correction notice that was published on February 18, 1977 (42 FR 10019). The proposed amendment exempted any sewage sludge incinerator located at a municipal waste treatment plant having a dry sludge capacity below 140 kg/hr (300 lb/hr), and where it would not be feasible to dispose of the sludge by land application or in a sanitary landfill because of freezing conditions. Prompting this amendment was a request by the State of Alaska which noted (1) the limited availability of small sludge incinerators which can meet the particulate matter standard, and (2) the difficulty of using landfills as an alternative means of sewage sludge disposal in some Alaskan communities because of permafrost conditions.

During the comment period on that proposal, four comment letters were received. Copies of these letters and a summary of the comments with EPA's responses are available for public inspection and copying at the EPA Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street SW., Washington, D.C. In addition, copies of the comment summary and Agency responses may be obtained upon written request from the Public Information Center (PM-215), Environmental Protection Agency, 401 M Street SW., Washington, D.C. 20460 (specify Public Comment Summary: Amendment to Standards of performance for Sewage Treatment Plants).

One commenter requested that industrial sludge incineration also be exempted by this revision. Only incinerators which burn sludge produced by municipal sewage treatment plants are covered by Subpart O. Incineration of industrial sludges are not covered because they may involve special metal, toxic and radioactive waste problems which were not addressed by the original study for developing the standard.

Three other commenters questioned the applicability of the proposed amendment. One questioned the need for the proposed exemption, arguing that small incinerators with control devices sufficient to meet the existing particulate emission standard of 0.65 g/kg dry sludge input are commercially available and should be used. Two others recommended wording to broaden the proposed exemption. They suggested that the amendment as proposed is too restrictive, considering the conditions faced by small communities in Alaska. One noted that high water-table levels severely limit land disposal of sludge in many areas. The other made a similar comment but attributed the problem to high rainfall as well.

Based upon these comments, EPA reevaluated the need for the proposed exemption. EPA recognizes that at least one type of incinerator (the fluidized-bed type) can be constructed in size categories of less than 140 kg/hr (300 lb/hr) and with emission control equipment capable of achieving the existing standard. However, separate sludge disposal by an incinerator dedicated exclusively to sewage sludge is unduly costly for a small community. This conclusion is based on data contained in two EPA publications: A Guide to the Selection of Cost-Effective Wastewater Treatment Systems (EPA-430/9-75-002), and Municipal Sludge Management: EPA Construction Grants Program—An Overview of the Sludge Management Situation (EPA-430/9-76-009). Sludge incineration costs, especially those for operation and maintenance, were compared for sewage treatment plants of 1 and 10 million gallons per day (mgd) capacity. Costs for a 1 mgd plant (about 1000 kg of dry sludge per day) were 100 to 300 percent higher than those for a 10 mgd facility. A small, remote community which already incinerates its other municipal wastes would bear the heaviest burden if forced to incinerate its sewage sludge separately.

In most instances, neither municipal waste nor sewage sludge incinerators are constructed because land disposal is a more cost-effective alternative. The coincineration of sewage sludge with solid waste should be a cost-effective and energy-efficient disposal alternative whenever land disposal options are not reasonably available. Since high water table levels, high annual precipitation, freezing conditions, and other factors limit or preclude the land application or sanitary landfilling of sludge, EPA has decided to broaden the exemption. Only freezing conditions were considered in the proposed exemption. However, an exemption based on these additional factors would be difficult to enforce due to climatic variability.

In order to make the exemption sufficiently broad and readily enforceable, EPA has decided to exempt incinerators that burn not more than 1000 kg per day of sewage sludge from municipal sewage treatment plants provided that the sewage sludge (dry basis) does not comprise, by weight, more than 10 percent of the total waste burned. The exemption provides relief only when sewage sludge is co-incinerated with municipal wastes, since any incinerator combusting more than 10 percent sewage sludge is affected by the emission standard regardless of the amount of sludge combusted. This approach, is based principally on the economics of sewage waste disposal and applies to any small community faced with very difficult land disposal conditions. It allows disposal of small quantities of sewage sludge in incinerators primarily combusting municipal refuse.

Currently, sludge incineration for small communities is 50 to 100 percent more costly per ton of dry sludge than land application or sanitary landfilling. Even though EPA is proposing criteria for landfill design and operation, the costs of incineration are expected to remain significantly higher. Thus, it is expected that this exemption will not cause a shift to incineration, but will only provide relief in areas where land disposal is either infeasible or very costly.

The purpose of the amendment is to relieve small communities (<9,000 population) of the burden of constructing separate incinerators for municipal wastes and sewage sludge in areas where land disposal is not feasible. Co-incineration of sewage sludge with solid wastes is less costly than separate sludge incineration and provides an energy benefit in lower auxiliary fuel consumption. Without this amendment, any co-incineration facility would have been considered a sludge incinerator under Subpart O.

Since sludge incineration costs decline as the quantities disposed of increase, this amendment limits the exemption to co-incineration units burning not more than 1000 kg (2205 lb) dry sludge per day. At an average generation rate of 0.11 kg (0.25 lb) dry sludge per person per day, the 1000 kg limit represents a population of approximately 9,000 persons. The 10 percent sludge allowance in such co-incineration is based on the fact that an average community generates about 14 times as much solid waste per person as dry sludge. Thus the 10 percent allowance should easily permit a small community to co-incinerate all its sludge and solid waste in one facility.

This amendment does not affect the applicability of the National Emission Standard for Mercury under 40 CFR Part 61. However, significant mercury wastes are usually not found in sewage sludge from small communities, but are more commonly found in metropolitan wastes from industrial activity.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect emission limits achievable with the best adequately demonstrated systems of emission reduction considering the cost of such systems. State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources.

States are free under section 116 of the Act to establish even more stringent emission limits than those necessary to attain or maintain the NAAQS under section 110 or those for new sources established under section 111. Thus, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: November 3, 1977.

DOUGLAS M. COSTLE,
Administrator.

In 40 CFR Part 60, Subpart O is amended by revising § 60.150 and § 60.153 as follows:

§ 60.150 Applicability and designation of affected facility.

(a) The affected facility is each incinerator that combusts wastes containing more than 10 percent sewage sludge (dry basis) produced by municipal sewage treatment plants, or each incinerator that charges more than 1000 kg (2205 lb) per day municipal sewage sludge (dry basis).

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.153 Monitoring of operations.

(a) The owner or operator of any sludge incinerator subject to the provisions of this subpart shall:

(1) Install, calibrate, maintain, and operate a flow measuring device which can be used to determine either the mass or volume of sludge charged to the incinerator. The flow measuring device shall have an accuracy of ±5 percent over its operating range.

(2) Provide access to the sludge charged so that a well mixed representative grab sample of the sludge can be obtained.

(3) Install, calibrate, maintain, and operate a weighing device for determining the mass of any municipal solid waste charged to the incinerator when sewage sludge and municipal solid waste are incinerated together. The weighing device shall have an accuracy of ±5 percent over its operating range.

(Sections 111, 114, 301(a) of the Clean Air Act as amended [42 U.S.C. 1857c-6, 1857c-9, 1857g(a)].)

[FR Doc.77-32667 Filed 11-9-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 217

THURSDAY, NOVEMBER 10, 1977

76

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 803-8]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Opacity Provisions for Fossil-Fuel-Fired Steam Generators

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule revises the format of the opacity standard and establishes reporting requirements for excess emissions of opacity for fossil-fuel-fired steam generators. This action is needed to make the standard and reporting requirements conform to changes in the Reference Method for determining opacity which were promulgated on November 12, 1974, (39 FR 39872). The intended effect is to limit opacity of emissions in order to insure proper operation and maintenance of facilities subject to standards of performance.

EFFECTIVE DATE: This rule is effective on December 5, 1977.

ADDRESSES: A summary of the public comments received on the September 10, 1975 (40 FR 42028), proposed rule with EPA's responses is available for public inspection and copying at the EPA Public Information Reference Unit (EPA Library), room 2922, 401 M Street SW., Washington, D.C. 20460. In addition, copies of the comment summary may be obtained by writing to the EPA Public Information Center (PM-215), Washington, D.C. 20460 (specify: "Public Comment Summary: Steam Generator Opacity Exception (40 FR 42028)").

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone: 919-541-5271.

SUPPLEMENTARY INFORMATION: The standards of performance for fossil-fuel-fired steam generators as promulgated under Subpart D of Part 60 in December 23, 1971, (36 FR 24876) allow emissions up to 20 percent opacity, except 40 percent is allowed for two minutes in any hour. On October 15, 1973, (38 FR 28564) a provision was added to Subpart D which required reporting as excess emissions all hourly periods during which there were three or more one-minute periods when average opacity exceeds 20 percent. Changes to the opacity provisions of Subpart A, General Provisions, and to Reference Method 9, Visual Determination of the Opacity of Emissions from Stationary Sources, were promulgated on November 12, 1974 (39

FR 39872). Among these changes is a requirement that opacity be determined by averaging 24 readings taken at 15-second intervals. Because of this change, the Agency reassessed the opacity standard originally promulgated under Subpart D, and on September 10, 1975, proposed amendments to the opacity standard and reporting requirements. Specifically, these amendments would have deleted the permissible exemption (two minutes per hour of emissions of 40 percent opacity) for gaseous and solid fossil fuels.

The proposed amendment to the opacity provisions was based on a review of available data particularly with respect to the challenge to the opacity standards for coal-fired steam generators (*Essex Chemical Corp. et al.* v. *Ruckelshaus, Appalachian Power Co., et al.* vs. *EPA*, 486 F.2d 427, September 10, 1973). Information available at that time indicated that the two-minute exception allowed under § 60.42(a)(2) was unnecessary for large steam generators fired with solid and gaseous fossil fuels.

Interested parties were invited to submit comments. A total of 10 interested parties, including State agencies, electric utility firms, and industrial firms submitted comments. Following a review of the proposed amendments and consideration of the comments, the amendments have been revised and are being promulgated today.

While no information was submitted to show that the exception is needed for large utility steam generators equipped with conventional "cold side" electrostatic precipitators or with scrubbers or fabric filters, commenters contended that the two-minute exception is needed for industrial boilers and for all units equipped with so-called "hot side" electrostatic precipitators, (i.e., precipitators installed upstream of the air heater where temperatures are 590K to 700K). For industrial boilers in the size range of 73 to 220 MW (250 x 10^6 to 750 x 10^6 BTU per hour) heat input, commenters stated that the frequency of soot blowing would have to be increased significantly over present practices if the exception were deleted. More frequent soot blowing would increase costs and energy requirements considerably without any decrease in particulate emissions. Operators of "hot side" precipitators pointed out that where hot side precipitators are used, soot-blowing opacity exceptions are necessary to allow cleaning of the air heater. They noted that since the air heaters are downstream of "hot side" precipitators, any particulate which is removed by soot-blowing will be released with exhaust gases and will contribute to opacity.

EPA has concluded that for steam generators designed for compliance with the particulate matter standard of performance, there are legitimate reasons for providing a limited exception to the opacity standard, and thus, while the format of the opacity standard is revised, the opacity exemption for coal-fired units is retained. The exception could be deleted for gaseous fossil fuel, but since opacity is not a problem from gas-fired units, there is no need to further complicate the regulation by deleting the exception for gas. The two-minute exception could be deleted for very large coal-fired units (>220 MW heat input) that are not equipped with hot side precipitators, but again the deletion would have little effect and would needlessly complicate the regulation.

Section 60.42(a)(2) is amended by expressing the two-minute 40 percent opacity exception in terms of a six-minute 27 percent average opacity (a weighted average of two minutes at 40 percent opacity and four minutes at 20 percent opacity) for consistency with Reference Method 9. This change does not alter the stringency of the standard. In addition, § 60.45(g)(1) which was reserved on October 6, 1975, (40 FR 46250) pending resolution of the opacity exception, is added to require reporting as excess emissions any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except for the one permissible six-minute period per hour of up to 27 percent opacity.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: November 23, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.42(a)(2) is revised as follows:

§ 60.42 Standard for particulate matter.

(a) * * *

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(Sec. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601).)

2. Section 60.45(g)(1) is added as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(g) * * *

(1) *Opacity.* Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(Sec. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

[FR Doc.77-34641 Filed 12-2-77;8:45 am]

77

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the Commonwealth of Puerto Rico

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: A notice announcing EPA's delegation of authority for the New Source Performance Standards to the Commonwealth of Puerto Rico is published at page 62196 of today's FEDERAL REGISTER. In order to reflect this delegation, this document amends EPA regulations to require the submission of all notices, reports, and other communications called for by the delegated regulations to the Commonwealth of Puerto Rico as well as to EPA.

EFFECTIVE DATE: December 9, 1977.

FOR FURTHER INFORMATION CONTACT:

J. Kevin Healy, Attorney, U.S. Environmental Protection Agency, Region II, General Enforcement Branch, Enforcement Division, 26 Federal Plaza, New York, N.Y. 10007, 212-264-1196.

SUPPLEMENTARY INFORMATION: By letter dated January 13, 1977 EPA delegated authority to the Commonwealth of Puerto Rico to implement and enforce the New Source Performance Standards. The Commonwealth accepted this delegation by letter dated October 17, 1977. A full account of the background to this action and of the exact terms of the delegation appears in the Notice of Delegation which is also published in today's FEDERAL REGISTER.

This rulemaking is effective immediately, since the Administrator has found good cause to forgo prior public notice. This addition of the Commonwealth of Puerto Rico address to the Code of Federal Regulations is a technical change and imposes no additional substantive burden on the parties affected.

Dated: November 22, 1977.

ECKARDT C. BECK,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

(1) In § 60.4 paragraph (b) is amended by revising subparagraph (BBB) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(AAA) * * *

(BBB)—Commonwealth of Puerto Rico: Commonwealth of Puerto Rico Environmental Quality Board, P.O. Box 11785, Santurce, P.R. 00910.

* * * * *

[FR Doc.77-35162 Filed 12-8-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 237

FRIDAY, DECEMBER 9, 1977

78

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 838-3]

AIR POLLUTION

Delegation of Authority to the State of Minnesota for Prevention of Significant Deterioration; Inspections, Monitoring and Entry; Standards of Performance for New Stationary Sources; and National Emission Standards for Hazardous Air Pollutants

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The amendment below institutes an address change for the implementation of technical and administrative review and enforcement of Prevention of Significant Deterioration provisions; Inspections, Monitoring and Entry provisions; Standards of Performance for New Stationary Sources; and National Emission Standards for Hazardous Air Pollutants. The notice announcing the delegation of authority is published elsewhere in this issue of the FEDERAL REGISTER.

EFFECTIVE DATE: October 6, 1977.

ADDRESSES: This amendment provides that all reports, requests, applications, and communications required for the delegated authority will no longer be sent to the U.S. Environmental Protection Agency, Region V Office, but will be sent instead to: Minnesota Pollution Control Agency, Division of Air Quality, 1935 West County Road B-2, Roseville, Minn. 55113.

FOR FURTHER INFORMATION, CONTACT:

Joel Morbito, Air Programs Branch, U.S. Environmental Protection Agency, Region V, 230 South Dearborn St., Chicago, Ill. 60604, 312-353-2205.

SUPPLEMENTARY INFORMATION: The Regional Administrator finds good cause for forgoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegations which are granted by this administrative amendment were effective October 6, 1977, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations. This rulemaking is effective immediately and is issued under authority of sections 101, 110, 111, 112, 114, 160–169 of the Clean Air Act, as amended (42 U.S.C. 7401, 7410, 7411, 7412, 7414,–7470–79, 7491). Accordingly, 40 CFR Parts 52, 60 and 61 are amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

Subpart Y—Minnesota

1. Section 52.1224 is amended by adding a new paragraph (b)(5) as follows:

§ 52.1224 General requirements.

* * * * *

(b) * * *

(5) Authority of the Regional Administrator to make available information and data was delegated to the Minnesota Pollution Control Agency effective October 6, 1977.

3. Section 52.1234 is amended by adding a new paragraph (c) as follows:

§ 52.1234 Significant deterioration of air quality.

* * * * *

(c) All applications and other information required pursuant to § 52.21 from sources located in the State of Minnesota shall be submitted to the Minnesota Pollution Control Agency, Division of Air Quality, 1935 West County Road B-2, Roseville, Minn. 55113.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart A—General Provisions

1. Section 60.4 is amended by adding a new paragraph (b)(Y) as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(Y) Minnesota Pollution Control Agency, Division of Air Quality, 1935 West County Road B-2, Roseville, Minn. 55113.

FEDERAL REGISTER, VOL. 43, NO. 1

TUESDAY, JANUARY 3, 1978

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79

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Revision of Reference Method 11

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action revises reference method 11, the method for determining the hydrogen sulfide content of fuel gas streams. The revision is made because EPA found that interferences resulting from the presence of mercaptans in some refinery fuel gases can lead to erroneous test data when the current method is used. This revision eliminates the problem of mercaptan interference and insures the accuracy of the test data.

EFFECTIVE DATE: January 10, 1978.

ADDRESSES: Copies of the comment letters responding to the proposed revision published in the FEDERAL REGISTER on May 23, 1977 (42 FR 26222), and a summary of the comments with EPA's responses are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C. 20460. A copy of the summary of comments and EPA's responses may be obtained by writing the Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711. When requesting this document, "Comments and Responses Summary: Revision of Reference Method 11," should be specified.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On March 8, 1974, the Environmental Protection Agency promulgated standards of performance limiting emissions of sulfur dioxide from new, modified, and reconstructed fuel gas combustion devices at petroleum refineries. At the same time, reference method 11 was promulgated as the performance test method for measuring H_2S in the fuel gases. It was found after the promulgation of method 11 that interference resulting from the presence of mercaptans in some refinery fuel gases can lead to erroneous test results in those cases where mercaptans were present in significant concentrations.

Following studies of the problems related to reference method 11, it was decided to revise the method and the revision was proposed in the FEDERAL REGISTER on May 23, 1977. The major change in the proposed revision from the original promulgation was a substitution of a new absorbing solution that is essentially free from mercaptan interference. New sections were also added which described the range and sensitivity, interferences, and precision and accuracy of the revision.

There were seven comments received concerning the proposed revision. Five were received from industry, one from a local environmental control agency and one from a research laboratory. None of the comments warranted any significant changes of the proposed revision. The final revision differs from the revision proposed on May 23, 1977, in only one respect: Phenylarsine oxide standard solution has been included as an acceptable titrant in lieu of sodium thiosulfate.

The effective date of this regulation is January 10, 1978, because section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions of them become effective upon promulgation.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an economic impact analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: December 29, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I of Title 40 of the Code of Federal Regulations is amended by revising Method 11 of Appendix A—Reference Methods as follows:

APPENDIX A.—REFERENCE METHODS

* * * * *

METHOD 11—DETERMINATION OF HYDROGEN SULFIDE CONTENT OF FUEL GAS STREAMS IN PETROLEUM REFINERIES

1. *Principle and applicability.* 1.1 *Principle.* Hydrogen sulfide (H_2S) is collected from a source in a series of midget impingers and absorbed in pH 3.0 cadmium sulfate ($CdSO_4$) solution to form cadmium sulfide (CdS). The latter compound is then measured iodometrically. An impinger containing hydrogen peroxide is included to remove SO_2 as an interfering species. This method is a revision of the H_2S method originally published in the FEDERAL REGISTER, Volume 39, No. 47, dated Friday, March 8, 1974.

1.2 *Applicability.* This method is applicable for the determination of the hydrogen sulfide content of fuel gas streams at petroleum refineries.

2. *Range and sensitivity.* The lower limit of detection is approximately 8 mg/m^3 (6 ppm). The maximum of the range is 740 mg/m^3 (520 ppm).

3. *Interferences.* Any compound that reduces iodine or oxidizes iodide ion will interfere in this procedure, provide it is collected in the cadmium sulfate impingers. Sulfur dioxide in concentrations of up to 2,600 mg/m^3 is eliminated by the hydrogen peroxide solution. Thiols precipitate with hydrogen sulfide. In the absence of H_2S, only co-traces of thiols are collected. When methane- and ethane-thiols at a total level of 300 mg/m^3 are present in addition to H_2S, the results vary from 2 percent low at an H_2S concentration of 400 mg/m^3 to 14 percent high at an H_2S concentration of 100 mg/m^3. Carbon oxysulfide at a concentration of 20 percent does not interfere. Certain carbonyl-containing compounds react with iodine and produce recurring end points. However, acetaldehyde and acetone at concentrations of 1 and 3 percent, respectively, do not interfere.

Entrained hydrogen peroxide produces a negative interference equivalent to 100 percent of that of an equimolar quantity of hydrogen sulfide. Avoid the ejection of hydrogen peroxide into the cadmium sulfate impingers.

4. *Precision and accuracy.* Collaborative testing has shown the within-laboratory coefficient of variation to be 2.2 percent and the overall coefficient of variation to be 5 percent. The method bias was shown to be —4.8 percent when only H_2S was present. In the presence of the interferences cited in section 3, the bias was positive at low H_2S concentrations and negative at higher concentrations. At 230 mg H_2S/m^3, the level of the compliance standard, the bias was +2.7 percent. Thiols had no effect on the precision.

5. *Apparatus.*

5.1 Sampling apparatus.

5.1.1 Sampling line. Six to 7 mm (¼ in.) Teflon[1] tubing to connect the sampling train to the sampling valve.

5.1.2 Impingers. Five midget impingers, each with 30 ml capacity. The internal diameter of the impinger tip must be 1 mm ±0.05 mm. The impinger tip must be positioned 4 to 6 mm from the bottom of the impinger.

5.1.3 Glass or Teflon connecting tubing for the impingers.

5.1.4 Ice bath container. To maintain absorbing solution at a low temperature.

5.1.5 Drying tube. Tube packed with 6- to 16-mesh indicating-type silica gel, or equivalent, to dry the gas sample and protect the meter and pump. If the silica gel has been used previously, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to approval of the Administrator.

NOTE.—Do not use more than 30 g of silica gel. Silica gel absorbs gases such as propane from the fuel gas stream, and use of excessive amounts of silica gel could result in errors in the determination of sample volume.

5.1.6 Sampling valve. Needle valve or equivalent to adjust gas flow rate. Stainless steel or other corrosion-resistant material.

5.1.7 Volume meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate (~1.0 liter/min) and conditions actually encountered during sampling. The meter shall be equipped with a temperature gauge (dial thermometer or equivalent) capable of measuring temperature to within 3° C (5.4° F). The gas meter should have a petcock, or equivalent, on the outlet connector which can be closed during the leak check. Gas volume for one revolution of the meter must not be more than 10 liters.

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[1] Mention of trade names of specific products does not constitute endorsement by the Environmental Protection Agency.

5.1.8 Flow meter. Rotameter or equivalent, to measure flow rates in the range from 0.5 to 2 liters/min (1 to 4 cfh).

5.1.9 Graduated cylinder, 25 ml size.

5.1.10 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby National Weather Service station, in which case, the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice-versa for elevation decrease.

5.1.11 U-tube manometer. 0–30 cm water column. For leak check procedure.

5.1.12 Rubber squeeze bulb. To pressurize train for leak check.

5.1.13 Tee, pinchclamp, and connecting tubing. For leak check.

5.1.14 Pump. Diaphragm pump, or equivalent. Insert a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter. The pump is used for the air purge at the end of the sample run; the pump is not ordinarily used during sampling, because fuel gas streams are usually sufficiently pressurized to force sample gas through the train at the required flow rate. The pump need not be leak-free unless it is used for sampling.

5.1.15 Needle valve or critical orifice. To set air purge flow to 1 liter/min.

5.1.16 Tube packed with active carbon. To filter air during purge.

5.1.17 Volumetric flask. One 1,000 ml.

5.1.18 Volumetric pipette. One 15 ml.

5.1.19 Pressure-reduction regulator. Depending on the sampling stream pressure, a pressure-reduction regulator may be needed to reduce the pressure of the gas stream entering the Teflon sample line to a safe level.

5.1.20 Cold trap. If condensed water or amine is present in the sample stream, a corrosion-resistant cold trap shall be used immediately after the sample tap. The trap shall not be operated below 0° C (32° F) to avoid condensation of C_3 or C_4 hydrocarbons.

5.2 Sample recovery.

5.2.1 Sample container. Iodine flask, glass-stoppered: 500 ml size.

5.2.2 Pipette. 50 ml volumetric type.

5.2.3 Graduated cylinders. One each 25 and 250 ml.

5.2.4 Flasks. 125 ml, Erlenmeyer.

5.2.5 Wash bottle.

5.2.6 Volumetric flasks. Three 1,000 ml.

5.3 Analysis.

5.3.1 Flask. 500 ml glass-stoppered iodine flask.

5.3.2 Burette. 50 ml.

5.3.3 Flask. 125 ml, Erlenmeyer.

5.3.4 Pipettes, volumetric. One 25 ml; two each 50 and 100 ml.

5.3.5 Volumetric flasks. One 1,000 ml; two 500 ml.

5.3.6 Graduated cylinders. One each 10 and 100 ml.

6. *Reagents.* Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available. Otherwise, use best available grade.

6.1 Sampling.

6.1.1 Cadmium sulfate absorbing solution. Dissolve 41 g of $3CdSO_4 \cdot 8H_2O$ and 15 ml of 0.1 M sulfuric acid in a 1-liter volumetric flask that contains approximately ¾ liter of deionized distilled water. Dilute to volume with deionized water. Mix thoroughly. pH should be 3±0.1. Add 10 drops of Dow-Corning Antifoam B. Shake well before use. If Antifoam B is not used, the alternate acidified iodine extraction procedure (section 7.2.2) must be used.

6.1.2 Hydrogen peroxide, 3 percent. Dilute 30 percent hydrogen peroxide to 3 percent as needed. Prepare fresh daily.

6.1.3 Water. Deionized, distilled to conform to ASTM specifications D1193-72, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

6.2 Sample recovery.

6.2.1 Hydrochloric acid solution (HCl), 3M. Add 240 ml of concentrated HCl (specific gravity 1.19) to 500 ml of deionized, distilled water in a 1-liter volumetric flask. Dilute to 1 liter with deionized water. Mix thoroughly.

6.2.2 Iodine solution 0.1 N. Dissolve 24 g of potassium iodide (KI) in 30 ml of deionized, distilled water. Add 12.7 g of resublimed iodine (I_2) to the potassium iodide solution. Shake the mixture until the iodine is completely dissolved. If possible, let the solution stand overnight in the dark. Slowly dilute the solution to 1 liter with deionized, distilled water, with swirling. Filter the solution if it is cloudy. Store solution in a brown-glass reagent bottle.

6.2.3 Standard iodine solution, 0.01 N. Pipette 100.0 ml of the 0.1 N iodine solution into a 1-liter volumetric flask and dilute to volume with deionized, distilled water. Standardize daily as in section 8.1.1. This solution must be protected from light. Reagent bottles and flasks must be kept tightly stoppered.

6.3 Analysis.

6.3.1 Sodium thiosulfate solution, standard 0.1 N. Dissolve 24.8 g of sodium thiosulfate pentahydrate ($Na_2S_2O_3 \cdot 5H_2O$) or 15.8 g of anhydrous sodium thiosulfate ($Na_2S_2O_3$) in 1 liter of deionized, distilled water and add 0.01 g of anhydrous sodium carbonate (Na_2CO_3) and 0.4 ml of chloroform ($CHCl_3$) to stabilize. Mix thoroughly by shaking or by aerating with nitrogen for approximately 15 minutes and store in a glass-stoppered, reagent bottle. Standardize as in section 8.1.2.

6.3.2 Sodium thiosulfate solution, standard 0.01 N. Pipette 50.0 ml of the standard 0.1 N thiosulfate solution into a volumetric flask and dilute to 500 ml with distilled water.

NOTE.—A 0.01 N phenylarsine oxide solution may be prepared instead of 0.01 N thiosulfate (see section 6.3.3).

6.3.3 Phenylarsine oxide solution, standard 0.01 N. Dissolve 1.80 g of phenylarsine oxide (C_6H_5AsO) in 150 ml of 0.3 N sodium hydroxide. After settling, decant 140 ml of this solution into 800 ml of distilled water. Bring the solution to pH 6–7 with 6N hydrochloric acid and dilute to 1 liter. Standardize as in section 8.1.3.

6.3.4 Starch indicator solution. Suspend 10 g of soluble starch in 100 ml of deionized, distilled water and add 15 g of potassium hydroxide (KOH) pellets. Stir until dissolved, dilute with 900 ml of deionized distilled water and let stand for 1 hour. Neutralize the alkali with concentrated hydrochloric acid, using an indicator paper similar to Alkacid test ribbon, then add 2 ml of glacial acetic acid as a preservative.

NOTE.—Test starch indicator solution for decomposition by titrating, with 0.01 N iodine solution, 4 ml of starch solution in 200 ml of distilled water that contains 1 g potassium iodide. If more than 4 drops of the 0.01 N iodine solution are required to obtain the blue color, a fresh solution must be prepared.

7. *Procedure.*

7.1 Sampling.

7.1.1 Assemble the sampling train as shown in figure 11-1, connecting the five midget impingers in series. Place 15 ml of 3 percent hydrogen peroxide solution in the first impinger. Leave the second impinger empty. Place 15 ml of the cadmium sulfate absorbing solution in the third, fourth, and fifth impingers. Place the impinger assembly in an ice bath container and place crushed ice around the impingers. Add more ice during the run, if needed.

7.1.2 Connect the rubber bulb and manometer to first impinger, as shown in figure 11-1. Close the petcock on the dry gas meter outlet. Pressurize the train to 25-cm water pressure with the bulb and close off tubing connected to rubber bulb. The train must hold a 25-cm water pressure with not more than a 1-cm drop in pressure in a 1-minute interval. Stopcock grease is acceptable for sealing ground glass joints.

NOTE.—This leak check procedure is optional at the beginning of the sample run, but is mandatory at the conclusion. Note also that if the pump is used for sampling, it is recommended (but not required) that the pump be leak-checked separately, using a method consistent with the leak-check procedure for diaphragm pumps outlined in section 4.1.2 of reference method 6, 40 CFR Part 60, Appendix A.

7.1.3 Purge the connecting line between the sampling valve and first impinger, by disconnecting the line from the first impinger, opening the sampling valve, and allowing process gas to flow through the line for a minute or two. Then, close the sampling valve and reconnect the line to the impinger train. Open the petcock on the dry gas meter outlet. Record the initial dry gas meter reading.

7.1.4 Open the sampling valve and then adjust the valve to obtain a rate of approximately 1 liter/min. Maintain a constant (±10 percent) flow rate during the test. Record the meter temperature.

7.1.5 Sample for at least 10 min. At the end of the sampling time, close the sampling valve and record the final volume and temperature readings. Conduct a leak check as described in Section 7.1.2 above.

7.1.6 Disconnect the impinger train from the sampling line. Connect the charcoal tube and the pump, as shown in figure 11-1. Purge the train (at a rate of 1 liter/min) with clean ambient air for 15 minutes to ensure that all H_2S is removed from the hydrogen peroxide. For sample recovery, cap the open ends and remove the impinger train to a clean area that is away from sources of heat. The area should be well lighted, but not exposed to direct sunlight.

7.2 Sample recovery.

7.2.1 Discard the contents of the hydrogen peroxide impinger. Carefully rinse the contents of the third, fourth, and fifth impingers into a 500 ml iodine flask.

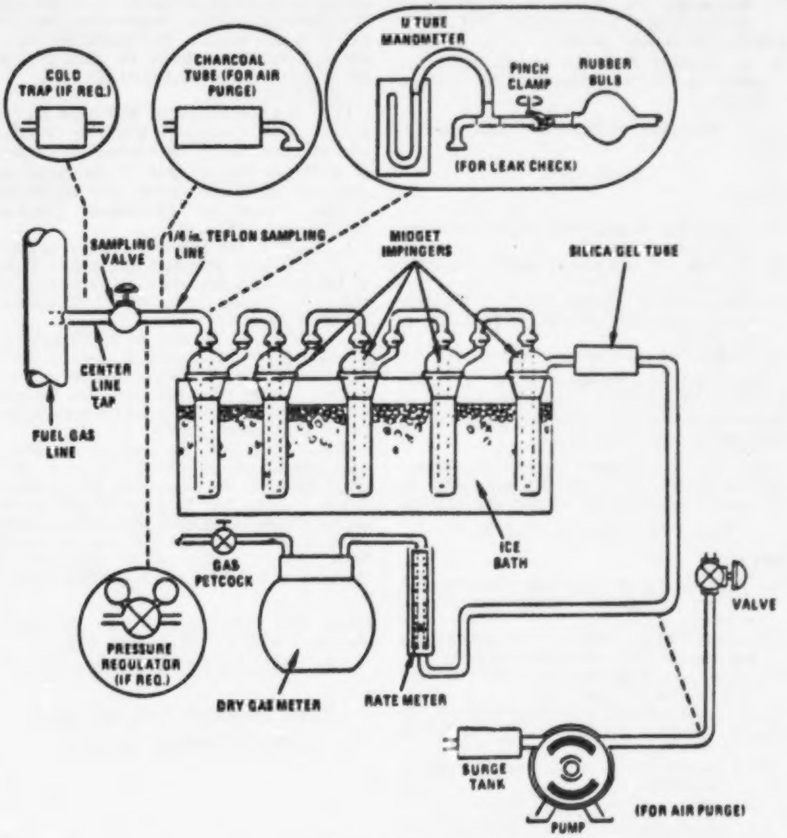

Figure 11-1. H_2S sampling train.

Note.—The impingers normally have only a thin film of cadmium sulfide remaining after a water rinse. If Antifoam B was not used or if significant quantities of yellow cadmium sulfide remain in the impingers, the alternate recovery procedure described below must be used.

7.2.2 Pipette exactly 50 ml of 0.01 N iodine solution into a 125 ml Erlenmeyer flask. Add 10 ml of 3 M HCl to the solution. Quantitatively rinse the acidified iodine into the iodine flask. Stopper the flask immediately and shake briefly.

7.2.2 (Alternate). Extract the remaining cadmium sulfide from the third, fourth, and fifth impingers using the acidified iodine solution. Immediately after pouring the acidified iodine into an impinger, stopper it and shake for a few moments, then transfer the liquid to the iodine flask. Do not transfer any rinse portion from one impinger to another; transfer it directly to the iodine flask. Once the acidified iodine solution has been poured into any glassware containing cadmium sulfide, the container must be tightly stoppered at all times except when adding more solution, and this must be done as quickly and carefully as possible. After adding any acidified iodine solution to the iodine flask, allow a few minutes for absorption of the H_2S before adding any further rinses. Repeat the iodine extraction until all cadmium sulfide is removed from the impingers. Extract that part of the connecting glassware that contains visible cadmium sulfide.

Quantitatively rinse all of the iodine from the impingers, connectors, and the beaker into the iodine flask using deionized, distilled water. Stopper the flask and shake briefly.

7.2.3 Allow the iodine flask to stand about 30 minutes in the dark for absorption of the H_2S into the iodine, then complete the titration analysis as in section 7.3.

Note.—Caution! Iodine evaporates from acidified iodine solutions. Samples to which acidified iodine have been added may not be stored, but must be analyzed in the time schedule stated in section 7.2.3.

7.2.4 Prepare a blank by adding 45 ml of cadmium sulfate absorbing solution to an iodine flask. Pipette exactly 50 ml of 0.01 N iodine solution into a 125-ml Erlenmeyer flask. Add 10 ml of 3 M HCl. Follow the same impinger extracting and quantitative rinsing procedure carried out in sample analysis. Stopper the flask, shake briefly, let stand 30 minutes in the dark, and titrate with the samples.

Note.—The blank must be handled by exactly the same procedure as that used for the samples.

7.3 Analysis.

Note.—Titration analyses should be conducted at the sample-cleanup area in order to prevent loss of iodine from the sample. Titration should never be made in direct sunlight.

7.3.1 Using 0.01 N sodium thiosulfate solution (or 0.01 N phenylarsine oxide, if applicable), rapidly titrate each sample in an iodine flask using gentle mixing, until solution is light yellow. Add 4 ml of starch indicator solution and continue titrating slowly until the blue color just disappears. Record V_{TT}, the volume of sodium thiosulfate solution used, or V_{AT}, the volume of phenylarsine oxide solution used (ml).

7.3.2 Titrate the blanks in the same manner as the samples. Run blanks each day until replicate values agree within 0.05 ml. Average the replicate titration values which agree within 0.05 ml.

8. *Calibration and standards.*

8.1 Standardizations.

8.1.1 Standardize the 0.01 N iodine solution daily as follows: Pipette 25 ml of the iodine solution into a 125 ml Erlenmeyer flask. Add 2 ml of 3 M HCl. Titrate rapidly with standard 0.01 N thiosulfate solution or with 0.01 N phenylarsine oxide until the solution is light yellow, using gentle mixing. Add four drops of starch indicator solution and continue titrating slowly until the blue color just disappears. Record V_T, the volume of thiosulfate solution used, or V_{AS}, the volume of phenylarsine oxide solution used (ml). Repeat until replicate values agree within 0.05 ml. Average the replicate titration values which agree within 0.05 ml and calculate the exact normality of the iodine solution using equation 9.3. Repeat the standardization daily.

8.1.2 Standardize the 0.1 N thiosulfate solution as follows: Oven-dry potassium dichromate ($K_2Cr_2O_7$) at 180 to 200° C (360 to 390° F). Weigh to the nearest milligram, 2 g of potassium dichromate. Transfer the dichromate to a 500 ml volumetric flask, dissolve in deionized, distilled water and dilute to exactly 500 ml. In a 500 ml iodine flask, dissolve approximately 3 g of potassium iodide (KI) in 45 ml of deionized, distilled water, then add 10 ml of 3 M hydrochloric acid solution. Pipette 50 ml of the dichromate solution into this mixture. Gently swirl the solution once and allow it to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of deionized distilled water, washing down the sides of the flask with part of the water. Titrate with 0.1 N thiosulfate until the solution is light yellow. Add 4 ml of starch indicator and continue titrating slowly to a green end point. Record V_S, the volume of thiosulfate solution used (ml). Repeat until replicate analyses agree within 0.05 ml. Calculate the normality using equation 9.1. Repeat the standardization each week, or after each test series, whichever time is shorter.

8.1.3 Standardize the 0.01 N Phenylarsine oxide (if applicable) as follows: oven dry potassium dichromate ($K_2Cr_2O_7$) at 180 to 200° C (360 to 390° F). Weigh to the nearest milligram, 2 g of the $K_2Cr_2O_7$; transfer the dichromate to a 500 ml volumetric flask, dissolve in deionized, distilled water, and dilute to exactly 500 ml. In a 500 ml iodine flask, dissolve approximately 0.3 g of potassium iodide (KI) in 45 ml of deionized, distilled water; add 10 ml of 3M hydrochloric acid. Pipette 5 ml of the $K_2Cr_2O_7$ solution into the iodine flask. Gently swirl the contents of the flask once and allow to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of deionized, distilled water, washing down the sides of the flask with part of the water. Titrate with 0.01 N phenylarsine oxide until the solution is light yellow. Add 4 ml of starch indicator and continue titrating slowly to a green end point. Record V_A, the volume of phenylarsine oxide used (ml). Repeat until replicate analyses agree within 0.05 ml. Calculate the normality using equation 9.2. Repeat the standardization each week or after each test series, whichever time is shorter.

8.2 Sampling train calibration. Calibrate the sampling train components as follows:

8.2.1 Dry gas meter.

8.2.1.1 Initial calibration. The dry gas meter shall be calibrated before its initial use in the field. Proceed as follows: First, assemble the following components in series: Drying tube, needle valve, pump, rotameter, and dry gas meter. Then, leak-check the system as follows: Place a vacuum gauge (at least 760 mm Hg) at the inlet to the drying tube and pull a vacuum of 250 mm (10 in.) Hg; plug or pinch off the outlet of the flow meter, and then turn off the pump. The vacuum shall remain stable for at least 30 seconds. Carefully release the vacuum gauge before releasing the flow meter end.

Next, calibrate the dry gas meter (at the sampling flow rate specified by the method) as follows: Connect an appropriately sized wet test meter (e.g., 1 liter per revolution) to the inlet of the drying tube. Make three independent calibration runs, using at least five revolutions of the dry gas meter per run. Calculate the calibration factor, *Y* (wet test meter calibration volume divided by the dry gas meter volume, both volumes adjusted to the same reference temperature and pressure), for each run, and average the results. If any *Y* value deviates by more than 2 percent from the average, the dry gas meter is unacceptable for use. Otherwise, use the average as the calibration factor for subsequent test runs.

8.2.1.2 Post-test calibration check. After each field test series, conduct a calibration check as in section 8.2.1.1. above, except for the following variations: (a) The leak check is not to be conducted, (b) three or more revolutions of the dry gas meter may be used, and (3) only two independent runs need be made. If the calibration factor does not deviate by more than 5 percent from the initial calibration factor (determined in section 8.2.1.1.), then the dry gas meter volumes obtained during the test series are acceptable. If the calibration factor deviates by more than 5 percent, recalibrate the dry gas meter as in section 8.2.1.1, and for the calculations, use the calibration factor (initial or recalibration) that yields the lower gas volume for each test run.

8.2.2 Thermometers. Calibrate against mercury-in-glass thermometers.

8.2.3 Rotameter. The rotameter need not be calibrated, but should be cleaned and maintained according to the manufacturer's instruction.

8.2.4 Barometer. Calibrate against a mercury barometer.

9. *Calculations.* Carry out calculations retaining at least one extra decimal figure beyond that of the acquired data. Round off results only after the final calculation.

9.1 Normality of the Standard (~0.1 N) Thiosulfate Solution.

$$N_s = 2.039 W/V_s$$

where:

W = Weight of $K_2Cr_2O_7$ used, g.
V_s = Volume of $Na_2S_2O_3$ solution used, ml.
N_s = Normality of standard thiosulfate solution, g-eq/liter.
2.039 = Conversion factor

(6 eq. I_2/mole $K_2Cr_2O_7$) (1,000 ml/liter)/= (294.2 g $K_2Cr_2O_7$/mole) (10 aliquot factor)

9.2 Normality of Standard Phenylarsine Oxide Solution (if applicable).

$$N_A = 0.2039 W/V_A$$

where:

W = Weight of $K_2Cr_2O_7$ used, g.
V_A = Volume of $C_6H_5A_sO$ used, ml.
N_A = Normality of standard phenylarsine oxide solution, g = eq/liter.
0.2039 = Conversion factor

(6 eq. I_2/mole $K_2Cr_2O_7$) (1,000 ml/liter)/(249.2 g $K_2Cr_2O_7$/mole) (100 aliquot factor)

9.3 Normality of Standard Iodine Solution.

$$N_I = N_T V_T / V_I$$

where:

N_I = Normality of standard iodine solution, g-eq/liter.
V_I = Volume of standard iodine solution used, ml.
N_T = Normality of standard (~0.01 N) thiosulfate solution; assumed to be 0.1 N_s, g-eq/liter.
V_T = Volume of thiosulfate solution used, ml.

NOTE.—If phenylarsine oxide is used intead of thiosulfate, replace N_T and V_T in Equation 9.3 with N_A and V_{AS}, respectively (see sections 8.1.1 and 8.1.3).

9.4 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C) and 760 mm Hg.

$$V_{m(std)} = V_m Y\,[(T_{std}/T_m)\,(P_{bar}/P_{std})]$$

where:

$V_{m(std)}$ = Volume at standard conditions of gas sample through the dry gas meter, standard liters.
V_m = Volume of gas sample through the dry gas meter (meter conditions), liters.
T_{std} = Absolute temperature at standard conditions, 293° K.
T_m = Average dry gas meter temperature, °K.
P_{bar} = Barometric pressure at the sampling site, mm Hg.
P_{std} = Absolute pressure at standard conditions, 760 mm Hg.
Y = Dry gas meter calibration factor.

9.5 Concentration of H_2S. Calculate the concentration of H_2S in the gas stream at standard conditions using the following equation:

$$C_{H_2S} = K[(V_{IT}N_I - V_{TT}N_T)\text{ sample} - (V_{IT}N_I - V_{TT}N_T)\text{ blank}]/V_{m(std)}$$

where (metric units):

C_{H_2S} = Concentration of H_2S at standard conditions, mg/dscm.
K = Conversion factor = 17.04×10^3

(34.07 g/mole H_2S) (1,000 liters/m^3) (1,000 mg/g)/=(1,000 ml/liter) (2H_2S eq/mole)

V_{IT} = Volume of standard iodine solution = 50.0 ml.
N_I = Normality of standard iodine solution, g-eq/liter.
V_{TT} = Volume of standard (~0.01 N) sodium thiosulfate solution, ml.
N_T = Normality of standard sodium thiosulfate solution, g-eq/liter.
$V_{m(std)}$ = Dry gas volume at standard conditions, liters.

NOTE.—If phenylarsine oxide is used instead of thiosulfate, replace N_T and V_{TT} in Equation 9.5 with N_A and V_{AT}, respectively (see Sections 7.3.1 and 8.1.3).

10. *Stability.* The absorbing solution is stable for at least 1 month. Sample recovery and analysis should begin within 1 hour of sampling to minimize oxidation of the acidified cadmium sulfide. Once iodine has been added to the sample, the remainder of the analysis procedure must be completed according to sections 7.2.2 through 7.3.2.

11. *Bibliography.*

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(Secs. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

[FR Doc. 78-482 Filed 1-9-78; 8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 846-7]

NEW SOURCE REVIEW

Delegation of Authority to the Commonwealth of Kentucky

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The amendments below institute certain address changes for reports and applications required from operators of new sources. EPA has delegated to the Commonwealth of Kentucky authority to review new and modified sources. The delegated authority includes the reviews under 40 CFR Part 52 for the prevention of significant deterioration. It also includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources and reviewed under 40 CFR Part 61 for national emission standards for hazardous air pollutants. A notice announcing the delegation of authority was published in the Notices section of a previous issue of the FEDERAL REGISTER. These amendments provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent to the Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, West Frankfort Office Complex, U.S. 127, Frankfort, Ky. 40601, instead of EPA's Region IV.

EFFECTIVE DATE: January 25, 1978.

FOR FURTHER INFORMATION, CONTACT:

John Eagles, Air Programs Branch, Environmental Protection Agency, Region IV, 345 Courtland Street NE., Atlanta, Ga. 30308, phone 404-881-2864.

SUPPLEMENTARY INFORMATION: The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on April 12, 1977, and it serves no purpose to delay the technical change of this addition of the state address to the Code of Federal Regulations.

(Secs. 101, 110, 111, 112, 301, Clean Air Act, as amended, (42 U.S.C. 7401, 7410, 7411, 7412, 7601).)

Dated: January 10, 1978.

JOHN C. WHITE,
Regional Administrator.

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

Part 52 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows:

Subpart S—Kentucky

1. Section 52.920(c) is amended by adding a new paragraph (c)(11) as follows:

§ 52.920 Identification of plan.

* * * * *

(c) * * *

(11) Letters requesting delegation of Federal authority for the administrative and technical portions of the Prevention of Significant Deterioration program were submitted on May 5 and July 13, 1976 by the Secretary of the Department for Natural Resources and Environmental Protection.

2. Section 52.931 is amended by adding a new paragraph (c) as follows:

§ 52.931 Significant deterioration of air quality.

* * * * *

(c) All applications and other information required pursuant to § 52.21 from sources located in the Commonwealth of Kentucky shall be submitted to the Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, West Frankfort Office Complex, U.S. 127, Frankfort, Ky. 40601, instead of the EPA Region IV office.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Part 60 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows:

3. In § 60.4, paragraph (b)(S) is added as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(S) Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Ky. 40601.

* * * * *

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Part 61 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows:

4. In § 61.04, paragraph (b)(S) is added as follows:

§ 61.04 Address.

* * * * *

(b) * * *

(S) Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Ky. 40601.

* * * * *

[FR Doc. 78-2032 Filed 1-24-78; 8:45 am]

81

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 856-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Delaware

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This document amends regulations concerning air programs to reflect delegation to the State of Delaware of authority to implement and enforce certain Standards of Performance for New Stationary Sources.

EFFECTIVE DATE: February 16, 1978.

FOR FURTHER INFORMATION CONTACT:

Stephen R. Wassersug, Director, Enforcement Division, Environmental Protection Agency, Region III, 6th and Walnut Streets, Philadelphia, Pa. 19106, 215-597-4171.

SUPPLEMENTARY INFORMATION:

I. BACKGROUND

On September 7, 1977, the State of Delaware requested delegation of authority to implement and enforce certain Standards of Performance for New Stationary Sources. The request was reviewed and on September 30, 1977 a letter was sent to Pierre S. DuPont IV, Governor, State of Delaware, approving the delegation and outlining its conditions. The approval letter specified that if Governor DuPont or any other representatives had any objections to the conditions of delegation they were to respond within ten (10) days after receipt of the letter. As of this date, no objections have been received.

II. REGULATIONS AFFECTED BY THIS DOCUMENT

Pursuant to the delegation of authority for certain Standards of Performance for New Stationary Sources to the State of Delaware, EPA is today amending 40 CFR 60.4, *Address,* to reflect this delegation. A Notice announcing this delegation (was) published on February 15, 1978, in the FEDERAL REGISTER. The amended § 60.4, which adds the address of the Delaware Department of Natural Resources and Environmental Control, to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

III. GENERAL

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on September 30, 1977, and it serves no purpose to delay the technical change of this address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended, 42 U.S.C. 1857c-6.

Dated: January 31, 1978.

JACK J. SCHRAMM,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (I) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(H) * * *

(I) State of Delaware (for fossil fuel-fired steam generators; incinerators; nitric acid plants; asphalt concrete plants; storage vessels for petroleum liquids; and sewage treatment plants only): Delaware Department of Natural Resources and Environmental Control, Edward Tatnall Building, Dover, Del. 19901.

[FR Doc. 78-4268 Filed 2-15-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 33

THURSDAY, FEBRUARY, 16, 1978

Title 40—Protection of the Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 833-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Kraft Pulp Mills

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The standards limit emissions of total reduced sulfur (TRS) and particulate matter from new, modified, and reconstructed kraft pulp mills. The standards implement the Clean Air Act and are based on the Administrator's determination that emissions from kraft pulp mills contribute significantly to air pollution. The intended effect of these standards is to require new, modified, and reconstructed kraft pulp mills to use the best demonstrated system of continuous emission reduction.

EFFECTIVE DATE: February 23, 1978.

ADDRESSES: The Standards Support and Environmental Impact Statement (SSEIS) may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711 (specify "Standards Support and Environmental Impact Statement, Volume 2: Promulgated Standards of Performance for Kraft Pulp Mills" (EPA-450/2-76-014b)). Copies of all comment letters received from interested persons participating in this rulemaking are available for inspection and copying during normal business hours at EPA's Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone No. 919-541-5271.

SUPPLEMENTARY INFORMATION: On September 24, 1976 (41 FR 42012), standards of performance were proposed for new, modified, and reconstructed kraft pulp mills under section 111 of the Clean Air Act, as amended. The significant comments that were received during the public comment period have been carefully reviewed and considered and, where determined by the Administrator to be appropriate, changes have been included in this notice of final rulemaking.

THE STANDARDS

The standards limit emissions of particulate matter from three affected facilities at kraft pulp mills. The limits are: 0.10 gram per dry standard cubic meter (g/dscm) at 8 percent oxygen for recovery furnaces, 0.10 gram per kilogram of black liquor solids (dry weight) (g/kg BLS) for smelt dissolving tanks, 0.15 g/dscm at 10 percent oxygen for lime kilns when burning gas, and 0.30 g/dscm at 10 percent oxygen for lime kilns when burning oil. Visible emissions from recovery furnaces are limited to 35 percent opacity.

The standards also limit emissions of TRS from eight affected facilities at kraft pulp mills. The limits are: 5 parts per million (ppm) by volume at 10 percent oxygen from the digester systems, multiple-effect evaporator systems, brown stock washer systems, black liquor oxidation systems, and condensate stripper systems; 5 ppm by volume at 8 percent oxygen from straight kraft recovery furnaces, 8 ppm by volume at 10 percent oxygen from lime kilns; and 25 ppm by volume at 8 percent oxygen from cross recovery furnaces, which are defined as furnaces burning at least 7 percent neutral sulfite semi-chemical (NSSC) liquor and having a green liquor sulfidity of at least 28 percent. In addition, TRS emissions from smelt dissolving tanks are limited to 0 0084 g/kg BLS.

The proposed TRS standard for the lime kiln has been changed, a separate TRS standard for cross recovery furnaces has been developed, and the proposed format of the standards for smelt dissolving tanks, digesters, multiple-effect evaporators, brown stock washers, black liquor oxidation and condensate strippers have been changed. The TRS, particulate matter and opacity standards for the other facilities, however, are essentially the same as those proposed.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect emission limits achievable with the best adequately demonstrated technological system of continuous emission reduction considering the cost of achieving such emission reductions and any nonair quality health, environmental, and energy impacts. State implementation plans (SIP's) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173(2) of the Clean Air Act, as amended in 1977, requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source, unless the owner or operator demonstrates that the source cannot achieve such an emission rate. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term "best available control technology" (BACT) means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines it achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, cost of achivement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty). Costs must be accorded far less weight in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Environmental and Economic Impact

The promulgated standards will reduce particulate emissions about 50 percent below requirements of the average existing State regulations. TRS emissions will be reduced by about 80 percent below requirements of the average existing State regulations, and this reduction will prevent odor problems from arising at most new kraft pulp mills. The secondary environmental impacts of the promulgated standard will be slight increases in water demand and wastewater treatment requirements. The energy impact of the promulgated standards will be small, increasing national energy consumption in 1980 by the equivalent of only 1.4 million barrels per year of No. 6 oil. The economic impact will be small with fifth-year annualized costs being estimated at $33 million.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register of a meeting of the National Air Pollution Control Techniques Advisory Committee. In addition, copies of the proposed standards and the Standards Support and Environmental Impact Statement (SSEIS) were distrubited to members of the kraft pulp industry and several environmental groups at the time of proposal. The public comment period extended from September 24, 1976, to March 14, 1977, and resulted in 42 comment letters with 28 of these letters coming from the industry, 12 from various regulatory agencies, and two from U.S. citizens. Several comments resulted in changes to the proposed standards. A detailed discussion of the comments and changes which resulted is presented in Volume 2 of the SSEIS. A summary is presented here.

Significant Comments and Changes Made in the Proposed Regulations

Most of the comment letters received contained multiple comments. The most significant comments and changes made to the proposed regulations are discussed below.

IMPACTS OF THE PROPOSED STANDARDS

Several commenters expressed concern about the increased energy consumption which would result from compliance with proposed standards. These commenters felt that this would conflict with the Department of Energy's goal to reduce total energy consumption in the pulp and paper industry by 14 percent. This factor was considered in the analysis of the energy impact associated with the standards and is discussed in the SSEIS. Although the standards will increase the difficulty of attaining this energy reduction goal, the 4.3 percent increase in energy usage that will be required by new, modified, or reconstructed by kraft pulp mills to comply with the standards is considered reasonable in comparison to the benefits which will result from the corresponding reduction in TRS and particulate matter emissions.

EMISSION CONTROL TECHNOLOGY

Most of the comments received regarding emission control technology concerned the application of this technology to either lime kilns or recovery furnaces. A few comments, however, expressed concern with the use of the oxygen correction factor included in the proposed standards for both lime kilns and recovery furnaces. These commenters pointed out that adjusting the concentration of particulate matter and TRS emissions to 10 percent oxygen for lime kilns and 8 percent oxygen for recovery furnaces only when the oxygen concentration exceeded these values effectively placed more stringent standards on the most energy-efficient operators. To ensure that the standard is equitable for all operators, these commenters suggested that the measured particulate matter and TRS concentrations should always be adjusted to 10 percent oxygen for the lime kiln and 8 percent oxygen for the recovery furnace.

These comments are valid. Requiring a lime kiln or recovery furnace with a low oxygen concentration to meet the same emission concentration as a lime kiln or recovery furnace with a high oxygen concentration would effectively place a more stringent emission limit on the kiln or furnace with the low oxygen concentration. Consequently, the promulgated standards require correction of particulate matter and TRS concentrations to 10 percent or 8 percent oxygen, as appropriate, in all cases.

Lime Kilns. Numerous comments were received on the emission control technology for lime kilns. The main points questioned by the commenters were: (a) Whether caustic scrubbing is effective in reducing TRS emissions from lime kilns; (b) whether an overdesign of the mud washing facilities at lime kiln E was responsible for the lower TRS emissions observed at this lime kiln; and (c) the adequacy of the data base used in developing the TRS standard.

The effectiveness of caustic scrubbing is substantiated by comparison of TRS emissions during brief periods when caustic was not being added to the scrubber at lime kiln E, with TRS emissions during normal operation at lime kiln E when caustic is being added to the scrubber. These observations clearly indicate that TRS emissions would be higher if caustic was not used in the scrubber. The ability of caustic scrubbing to reduce TRS emissions is also substantiated by the experience at another kraft pulp mill which was able to reduce TRS emissions from its lime kiln from 40-50 ppm to about 20 ppm merely by adding caustic to the scrubber. These factors, coupled with the emission data showing higher TRS emissions from those lime kilns which employed only efficient mud washing and good lime kiln process control, clearly show that caustic scrubbing reduces TRS emissions.

The mud washing facilities at lime kiln E are larger than those at other kraft pulp mills of equivalent pulp capacity. This "overdesign" resulted from initial plans of the company to process lime mud from waste water treatment. These waste water treatment plans were later abandoned. Since the quality or efficiency of mud washing has been shown to be a significant factor in reducing TRS emissions from lime kilns, the larger mud washing facilities at lime kiln E undoubtedly contributed to the low TRS emissions observed at this kiln. With the data available, however, it is not possible to separate the relative contribution of these mud washing facilities to the low TRS emissions observed from the relative contributions of good process operation of the lime kiln and caustic scrubbing.

Comments questioning the adequacy of the data base used in developing the standards for lime kilns were mainly directed toward the following points: the TRS standard was based on only one lime kiln; sampling losses which may have occurred during testing were not taken into account; and no lime kiln met both the TRS standard and the particulate standard.

As mentioned above, the TRS standard is based upon the emission control system installed at lime kiln E (i.e., efficient mud washing, good lime kiln process operation, and caustic scrubbing). While it is true that no other lime kiln in the United States is currently achieving the TRS emission levels observed at lime kiln E, there is no other lime kiln in the United States which is using the same emission control system that is employed at this facility. As discussed in the SSEIS, an analysis of the various parameters influencing TRS emissions from lime kilns indicates that this system of emission reduction could be applied to all new, modified, or reconstructed lime kilns and achieve the same reduction in emissions as observed at lime kiln E. Section 111 of the Clean Air Act requires that "standards of performance reflect the degree of emission reduction achievable through the application of the best system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." Litigation of standards of performance has resulted in clarification of the term "adequately demonstrated." In Portland Cement Association v. Ruckelshaus (486 F. 2d 375, D.C. Circuit, 1973), the standards of performance were viewed by the Court as "technology-forcing." Thus, while a system of emission reduction must be available for use to be considered adequately demonstrated, it does not have to be in routine use. However, in order to ensure that the numerical emission limit selected was consistent with proper operation and maintenance of the emission control system on lime kiln E, continuous monitoring data was examined. This analysis indicated that an emission source test of lime kiln E would have found TRS emission above 5 ppm greater than 5 percent of the time. This analysis also indicated, however, that it was very unlikely that an emission source test of lime kiln E would have found TRS emissions above 8 ppm. Thus, it appeared that the 5 ppm TRS numerical emission limit included in the proposed standard for lime kilns was too stringent. Accordingly, the numerical emission limit included in the promulgated TRS standard for lime kilns has been revised to 8 ppm. As discussed later in this preamble, consistent with this change in the numerical emission limit, the excess emissions allowance included within the emission monitoring requirements has been eliminated.

This does not reflect a change in the basis for the standard. The standard is still based on the best system of emission reduction, considering costs, for controlling TRS emissions from lime kilns (i.e., efficient mud washing, good lime kiln process operation, and caustic scrubbing). This system, or one equivalent to it, will still be required to comply with the standard.

Since proposal of the standards, sample losses of up to 20 percent during emission source testing have been confirmed. Although these losses were not considered in selecting the numerical emission limit included in the proposed TRS emission standard, they have been considered in selecting the numerical emission limit included in the promulgated standard. Also, since the amount of sample loss that occurs within the TRS emission measurement system during source testing can be determined, procedures have been added to Reference Method 16 requiring determination of these losses during each source test and adjustment of the emission data obtained to take these losses into account.

With regard to the ability of a lime kiln to comply with both the TRS emission standard and the particulate emission standard simultaneously, caustic scrubbing will tend to increase particulate emissions due to release of sodium fume from the scrubbing liquor. Compared to the concentration of particulate matter permitted in the gases discharged to the atmosphere, however, the potential contribution of sodium fume from caustic scrubbing is quite small. Consequently, with proper operation and maintenance, sodium fume due to caustic scrubbing will not cause particulate emissions from a lime kiln to exceed the numerical emission limit included in the promulgated standard.

Recovery Furnace. A number of comments were received regarding both the proposed TRS emission standard and the proposed particulate emission standard for recovery furnaces. Basically, the major issue was whether a cross recovery furnace could comply with the 5 ppm TRS standard or whether a separate standard was necessary.

Review of the data and information submitted with these comments indicates that the operation of cross recovery furnaces is substantially different from that of straight kraft recovery furnaces. The sulfidity of the black liquor burned in cross recovery furnaces and the heat content of the liquor, both of which are significant factors influencing TRS emissions, are considerably different from the levels found in straight kraft recovery furnaces.

Analysis of the data indicated that TRS emissions were generally less than 25 ppm, with only occasional excursions exceeding this level. Consequently, the promulgated TRS emission standard has been revised to include a separate TRS numerical emission limit of 25 ppm for cross recovery furnaces.

Smelt Dissolving Tank. Numerous comments were received concerning the format of the proposed TRS and particulate emission standards for smelt dissolving tanks. These comments pointed out that standards in terms of emissions per unit of air-dried pulp were inequitable for kraft pulp mills which produced low-yield pulps since both TRS and particulate emissions from the smelt dissolving tanks are proportional to the tons of black liquor solids fed into the tanks. The black liquor solids produced per ton of air-dried pulp, however, can vary substantially from mill to mill. A standard in terms of emissions per unit of air-dried pulp, therefore, requires greater control of emissions at kraft pulp mills which use low-yield pulps (higher solids-to-pulp ratio).

Review of these comments does indeed indicate that the format of the proposed standards was inequitable. The format of the promulgated standards, therefore, has been revised to emissions per unit of black liquor solids fed to the smelt dissolving tanks. Since the percent solids and black liquor flow rate to the recovery furnace is routinely monitored at kraft pulp mills, the weight of black liquor solids corresponding to a particular emissions period will be easy to determine.

Brown Stock Washers. Several comments expressed concern about combustion of the high volume-low TRS concentration gases discharged from brown stock washers and black liquor oxidation facilities in recovery furnaces without facing a serious risk of explosions. As discussed in the SSEIS, information obtained from two kraft pulp mill operators indicates that this practice is both safe and reliable when it is accompanied by careful engineering and operating practices. Danger of an explosion occurring is essentially eliminated by introducing the gases high in the furnace. Since some older furnaces do not have the capability to accept large volumes of gases at higher combustion ports, this practice may not be safe for some existing furnaces. In addition, the costs associated with altering these furnaces to accept these gases are frequently prohibitive. Consequently, the promulgated standards include an exemption for new, modified, or reconstructed brown stock washers and black liquor oxidation facilities within existing kraft pulp mills where combustion of these gases in an existing facility is not feasible from a safety or economic standpoint.

CONTINUOUS MONITORING

Numerous comments were received concerning the proposed continuous monitoring requirements. Generally, these comments questioned the requirement to install TRS monitors in light of the absence of performance specifications for these monitors.

At the time of proposal of the standards, both EPA and the kraft pulp mill industry were engaged in developing performance specifications for TRS continuous emission monitoring systems. It was expected that this work would lead to performance specifications for these monitoring systems by the time the standards of performance were promulgated. Unfortunately, this is not the case. In a joint EPA/industry effort, the compatibility of various TRS emission monitoring methods with Reference Method 16, which is the performance test method to determine TRS emissions, is still under study. There is little doubt but that these TRS emission monitoring systems will be shown to be compatible with Reference Method 16, and that performance specifications for these systems will be developed. Consequently, the promulgated standards include TRS continuous emission monitoring requirements. These requirements, however, will not become effective until performance specifications for TRS continuous emission monitoring systems have been developed. To accommodate this situation, not only for the promulgated standards for kraft pulp mills, but also for standards of performance that may be developed in the future that may also face this situation, section 60.13 of the General Provisions for subpart 60 is amended to provide that continuous monitoring systems need not be installed until performance specifications for these systems are promulgated under Appendix B to subpart 60. This will ensure that all facilities which are covered by standards of performance will eventually install continuous emission monitoring systems where required.

EXCESS EMISSIONS

Numerous comments were received which were concerned with the excess emission allowances and the reporting requirements for excess emissions. In general, these comments reflected a lack of understanding with regard to the concept of excess emissions. Consequently, a brief review of this concept is appropriate.

Standards of performance have two major objectives. The first is installation of the best system of emission reduction, considering costs; and the second is continued proper operation and maintenance of the system throughout its useful life. Since the numerical emission limit included in standards of performance is selected to reflect the performance of the best system of emission reduction under conditions of proper operation and maintenance, the performance test, under 40 CFR 60.8 represents the ability of the source to meet these objectives. Performance tests, however, are often time consuming and complex. As a result, while the performance test is an excellent mechanism for achieving these objectives, it is rather cumbersome and inconvenient for routinely achieving these objectives. Therefore, the Agency believes that continuous monitors must play an important role in meeting these objectives.

Excess emissions are defined as emissions exceeding the numerical emission limit included in a standard of performance. Continuous emission monitoring, therefore, identifies periods of excess emissions and when combined with the requirement that these periods be reported to EPA, it provides the Agency with a useful mechanism for achieving the previously mentioned objectives.

Continuous emission monitoring, however, will identify all periods of excess emissions, including those which are not the result of improper operation and maintenance. Excess emissions due to start-ups, shutdowns, and malfunctions, for example, are unavoidable or beyond the control of an owner or operator and cannot be attributed to improper operation and maintenance. Similarly, excess emissions as a result of some inherent variability or fluctation within a process which influences emissions cannot be attributed to improper operation and maintenance, unless these fluctations could be controlled by more carefully attending to those process operating parameters during routine operation which have little effect on operation of the process, but which may have a significant effect on emissions.

To quantify the potential for excess emissions due to inherent variability in a process, continuous monitoring data are used whenever possible to calculate an excess emission allowance. For TRS emissions at kraft pulp mills, this allowance is defined as follows. If a calendar quarter is divided into discrete contiguous 12-hour time periods, the excess emission allowance is expressed as the percentage of these time periods. Excess emissions may occur as the result of unavoidable variability within the kraft pulping process. Thus, the excess emissions allowance represents the potential for excess emissions under conditions of proper operation and maintenance in the absence of start-ups, shutdowns and malfunctions, and is used as a guideline or screening mechanism for interpreting the data generated by the excess emission reporting requirements.

Although the excess emission reporting requirements provide a mechanism for achieving the objective of proper operation and maintenance of the best system of emission reduction, this mechanism is not necessarily a direct indicator of improper operation and maintenance. Consequently, excess emission reports must be reviewed and interpreted for proper decisionmaking.

In general, the comments received concerning the excess emission reporting requirements questioned: (1) The adequacy of the TRS excess emission allowance for lime kilns and (2) the lack of a TRS excess emission allowance for recovery furnaces.

With regard to the adequacy of the TRS excess emissions allowance for lime kilns, a reevaluation of the TRS emission data from lime kiln E led the Agency to the conclusion that, for a TRS emission limit of 5 ppm, an excess emission allowance of 6 percent was appropriate. However, a similar analysis also indicates that an excess emission allowance is not appropriate at a TRS emission level of 8 ppm. Accordingly, the excess emission reporting requirements included in the promulgated standard for lime kilns contains no excess emission allowance. This does not represent a change in the basis of the standard. The standard will still require installation of the best system of emission reduction, considering costs (i.e., efficient mud washing, good lime kiln process operation, and caustic scrubbing; or an alternative system equivalent to the performance of this system).

With regard to the lack of a TRS excess emission allowance for recovery furnaces, at the time of proposal of the standards, no TRS continuous emission monitoring data were available from a well-controlled and well operated recovery furnace which could be used to determine an excess emission allowance. Several months of TRS continuous emission monitoring data, however, were submitted with the comments received from the operator of recovery furnace D concerning this point.

A review of the data indicates that, while some of the excursions of TRS emissions above 5 ppm reflected either improper operation and maintenance, or start-ups, shutdowns, or malfunctions, most of these excursions reflected unavoidable normal variability in the operation of a kraft pulp mill recovery furnace. Discounting those excursions in emissions from the data which were due to improper operation and maintenance, or start-ups, shutdowns, or malfunctions indicates that an excess emission allowance of 1 percent is appropriate for all recovery furnaces.

Including an excess emissions allowance in the promulgated standards for recovery furnaces, but not for lime kilns, is a reversal of the proposed requirements. Including such an allowance for recovery furnaces but not for lime kilns, however, is consistent with the nature of the different emission control systems which were selected as the bases for these standards. The emission control system upon which the TRS standard for recovery furnaces is based consists of black liquor oxidation and good process operation of the recovery furnace for direct recovery furnaces, and good process operation alone for indirect recovery furnaces. Neither of these emission control systems are particularly well suited to controlling fluctuations in the kraft pulping process. Thus, fluctuations in the process tend to pass through the emission control system and show up as fluctuations in TRS emissions.

The emission control system upon which the TRS standard for lime kilns is based consists of efficient mud washing, good process operation of the lime kiln, and caustic scrubbing of the gases discharged from the lime kiln. As with the emission control system upon which the standard for recovery furnaces is based, the first two emission control techniques (i.e., mud washing and good process operation) are not particularly well suited to controlling fluctuations in the kraft pulping process. The third emission control technique, however, caustic scrubbing, is an "add-on" emission control technique that can be designed to accommodate fluctuations in TRS emissions and minimize or essentially eliminate these fluctuations.

EMISSION TESTING

A few comments were received which questioned the validity of the results obtained by Reference Method 16, due to sample losses and sulfur dioxide (SO_2) interference.

With regard to the validity of the results obtained by Reference Method 16, as mentioned earlier, during the emission testing program, it was not widely known that sample losses could occur within the TRS emission measurement system. Since proposal of the standards, however, sample losses of up to 20 percent during emission source testing have been confirmed. Although these losses were not considered in selecting the numerical emission limits included in the proposed TRS emission standards, they have been considered in selecting the numerical emission limit included in the promulgated standards. Also, since the amount of sample loss that occurs within the TRS emission measurement system during source testing can be determined, procedures have been added to Reference Method 16 requiring determination of these losses during each source test and adjustment of the emission data obtained to take these losses into account. This will ensure that the TRS emission data obtained during a performance test are accurate.

It has also been confirmed that high concentrations of SO_2 will interfere with the determination of TRS emissions to some extent. At this point, however, it is not known what SO_2 concentration levels will result in a significant loss of accuracy in determining TRS emissions. The ability of a citrate scrubber to selectively remove SO_2 prior to measurement of TRS emissions is now being tested. In addition, various chromatographic columns might exist which would effectively resolve this problem. As soon as an appropriate technique is developed to overcome this problem, Reference Method 16 will be amended.

This problem of SO_2 interference will not present major difficulties to the use of Reference Method 16. Relatively high SO_2 concentration levels were observed in only one EPA emission source test. Accordingly, high SO_2 concentration levels are probably not a frequent occurrence within kraft pulp mills. More importantly, however, high SO_2 concentrations only interfere with the determination of methyl mercaptan in the emission measurement system outlined in Reference Method 16. Since methyl mercaptan is usually only a small contributor to total TRS emissions, neglecting methyl mercaptan where this interference occurs should not seriously affect the determination of TRS emissions. Consequently, Reference Method 16 can be used to enforce the promulgated standards without major difficulties.

Miscellaneous: The effective date of this regulation is February 24, 1976. Section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions of them become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (September 24, 1976).

NOTE.—An economic assessment has been prepared as required under section 317 of the Act. This also satisfies the requirements of Executive Orders 11821 and OMB Circular A-107.

Dated: February 10, 1978.

BARBARA BLUM,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

Subpart A—General Provisions

1. Section 60.13 is amended to clarify the provisions in paragraph (a) by revising paragraph (a) to read as follows:

§ 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring system under Appendix B to this part, unless:

(1) The continuous monitoring system is subject to the provisions of paragraphs (c)(2) and (c)(3) of this section, or

(2) otherwise specified in an applicable subpart or by the Administrator.

* * * * *

2. Part 60 is amended by adding subpart BB as follows:

Subpart BB—Standards of Performance for Kraft Pulp Mills

Sec.
60.280 Applicability and designation of affected facility.
60.281 Definitions.
60.282 Standard for particulate matter.
60.283 Standard for total reduced sulfur (TRS).
60.284 Monitoring of emissions and operations.
60.285 Test methods and procedures.

AUTHORITY: Secs. 111, 301(a) of the Clean Air Act, as amended [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart BB—Standards of Performance for Kraft Pulp Mills

60.280 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in kraft pulp mills: digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, recovery furnace, smelt dissolving tank, lime kiln, and condensate stripper system. In pulp mills where kraft pulping is combined with neutral sulfite semichemical pulping, the provisions of this subpart are applicable when any portion of the material charged to an affected facility is produced by the kraft pulping operation.

(b) Any facility under paragraph (a) of this section that commences construction or modification after September 24, 1976, is subject to the requirements of this subpart.

§ 60.281 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in Subpart A.

(a) "Kraft pulp mill" means any stationary source which produces pulp from wood by cooking (digesting) wood chips in a water solution of sodium hydroxide and sodium sulfide (white liquor) at high temperature and pressure. Regeneration of the cooking chemicals through a recovery process is also considered part of the kraft pulp mill.

(b) "Neutral sulfite semichemical pulping operation" means any operation in which pulp is produced from wood by cooking (digesting) wood chips in a solution of sodium sulfite and sodium bicarbonate, followed by mechanical defibrating (grinding).

(c) "Total reduced sulfur (TRS)" means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide, that are released during the kraft pulping operation and measured by Reference Method 16.

(d) "Digester system" means each continuous digester or each batch digester used for the cooking of wood in white liquor, and associated flash tank(s), below tank(s), chip steamer(s), and condenser(s).

(e) "Brown stock washer system" means brown stock washers and associated knotters, vacuum pumps, and filtrate tanks used to wash the pulp following the digester system.

(f) "Multiple-effect evaporator system" means the multiple-effect evaporators and associated condenser(s) and hotwell(s) used to concentrate the spent cooking liquid that is separated from the pulp (black liquor).

(g) "Black liquor oxidation system" means the vessels used to oxidize, with air or oxygen, the black liquor, and associated storage tank(s).

(h) "Recovery furnace" means either a straight kraft recovery furnace or a cross recovery furnace, and includes the direct-contact evaporator for a direct-contact furnace.

(i) "Straight kraft recovery furnace" means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains 7 weight percent or less of the total pulp solids from the neutral sulfite semichemical process or has green liquor sulfidity of 28 percent or less.

(j) "Cross recovery furnace" means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains more than 7 weight percent of the total pulp solids from the neutral sulfite semichemical process and has a green liquor sulfidity of more than 28 percent.

(k) "Black liquor solids" means the dry weight of the solids which enter the recovery furnace in the black liquor.

(l) "Green liquor sulfidity" means the sulfidity of the liquor which leaves the smelt dissolving tank.

(m) "Smelt dissolving tank" means a vessel used for dissolving the smelt collected from the recovery furnace.

(n) "Lime kiln" means a unit used to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

(o) "Condensate stripper system" means a column, and associated condensers, used to strip, with air or steam, TRS compounds from condensate streams from various processes within a kraft pulp mill.

§ 60.282 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any recovery furnace any gases which:

(i) Contain particulate matter in excess of 0.10 g/dscm (0.044 gr/dscf) corrected to 8 percent oxygen.

(ii) Exhibit 35 percent opacity or greater.

(2) From any smelt dissolving tank any gases which contain particulate matter in excess of 0.1 g/kg black liquor solids (dry weight)[0.2 lb/ton black liquor solids (dry weight)].

(3) From any lime kiln any gases which contain particulate matter in excess of:

(i) 0.15 g/dscm (0.067 gr/dscf) corrected to 10 percent oxygen, when gaseous fossil fuel is burned.

(ii) 0.30 g/dscm (0.13 gr/dscf) corrected to 10 percent oxygen, when liquid fossil fuel is burned.

§ 60.283 Standard for total reduced sulfur (TRS).

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the following conditions are met:

(i) The gases are combusted in a lime kiln subject to the provisions of paragraph (a)(5) of this section; or

(ii) The gases are combusted in a recovery furnace subject to the provisions of paragraphs (a)(2) or (a)(3) of this section; or

(iii) The gases are combusted with other waste gases in an incinerator or other device, or combusted in a lime kiln or recovery furnace not subject to the provisions of this subpart, and are subjected to a minimum temperature of 1200° F. for at least 0.5 second; or

(iv) It has been demonstrated to the Administrator's satisfaction by the owner or operator that incinerating the exhaust gases from a new, modified, or reconstructed black liquor oxidation system or brown stock washer system in an existing facility is technologically or economically not feasible. Any exempt system will become subject to the provisions of this subpart if the facility is changed so that the gases can be incinerated.

(2) From any straight kraft recovery furnace any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(3) From any cross recovery furnace any gases which contain TRS in excess of 25 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(4) From any smelt dissolving tank any gases which contain TRS in excess of 0.0084 g/kg black liquor solids (dry weight) [0.0168 lb/ton liquor solids (dry weight)].

(5) From any lime kiln any gases which contain TRS in excess of 8 ppm by volume on a dry basis, corrected to 10 percent oxygen.

§ 60.284 Monitoring of emissions and operations.

(a) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring systems:

(1) A continuous monitoring system to monitor and record the opacity of the gases discharged into the atmosphere from any recovery furnace. The span of this system shall be set at 70 percent opacity.

(2) Continuous monitoring systems to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from any lime kiln, recovery furnace, digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system, except where the provisions of § 60.283(a)(1) (iii) or (iv) apply. These systems shall be located downstream of the control device(s) and the span(s) of these continuous monitoring system(s) shall be set:

(i) At a TRS concentration of 30 ppm for the TRS continuous monitoring system, except that for any cross recovery furnace the span shall be set at 50 ppm.

(ii) At 20 percent oxygen for the continuous oxygen monitoring system.

(b) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device which measures the combustion temperature at the point of incineration of effluent gases which are emitted from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system where the provisions of § 60.283(a)(1)(iii) apply. The monitoring device is to be certified by the manufacturer to be accurate within ±1 percent of the temperature being measured.

(2) For any lime kiln or smelt dissolving tank using a scrubber emission control device:

(i) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the control equipment. The monitoring device is to be certified by the manufacturer to be accurate to within a gage pressure of ±500 pascals (ca. ±2 inches water gage pressure).

(ii) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±15 percent of design scrubbing liquid supply pressure. The pressure sensor or tap is to be located close to the scrubber liquid discharge point. The Administrator may be consulted for approval of alternative locations.

(c) Any owner or operator subject to the provisions of this subpart shall, except where the provisions of § 60.283(a)(1)(iv) or § 60.283(a)(4) apply.

(1) Calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(2) Calculate and record on a daily basis 12-hour average oxygen concentrations for the two consecutive periods of each operating day for the recovery furnace and lime kiln. These 12-hour averages shall correspond to the 12-hour average TRS concentrations under paragraph (c)(1) of this section and shall be determined as an arithmetic mean of the appropriate 12 contiguous 1-hour average oxygen concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(3) Correct all 12-hour average TRS concentrations to 10 volume percent oxygen, except that all 12-hour average TRS concentration from a recovery furnace shall be corrected to 8 volume percent using the following equation:

$$C_{corr} = C_{meas} \times (21 - X/21 - Y)$$

where:

C_{corr} = the concentration corrected for oxygen.

C_{meas} = the concentration uncorrected for oxygen.

X = the volumetric oxygen concentration in percentage to be corrected to (8 percent for recovery furnaces and 10 percent for lime kilns, incinerators, or other devices).

Y = the measured 12-hour average volumetric oxygen concentration.

(d) For the purpose of reports required under § 60.7(c), any owner or operator subject to the provisions of this subpart shall report periods of excess emissions as follows:

(1) For emissions from any recovery furnace periods of excess emissions are:

(i) All 12-hour averages of TRS concentrations above 5 ppm by volume for straight kraft recovery furnaces and above 25 ppm by volume for cross recovery furnaces.

(ii) All 6-minute average opacities that exceed 35 percent.

(2) For emissions from any lime kiln, periods of excess emissions are all 12-hour average TRS concentration above 8 ppm by volume.

(3) For emissions from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system periods of excess emissions are:

(i) All 12-hour average TRS concentrations above 5 ppm by volume unless the provisions of § 60.283(a)(1) (i), (ii), or (iv) apply; or

(ii) All periods in excess of 5 minutes and their duration during which the combustion temperature at the point of incineration is less than 1200° F. where the provisions of § 60.283(a)(1)(ii) apply.

(e) The Administrator will not consider periods of excess emissions reported under paragraph (d) of this section to be indicative of a violation of § 60.11(d) provided that:

(1) The percent of the total number of possible contiguous periods of excess emissions in a quarter (excluding periods of startup, shutdown, or malfunction and periods when the facility is not operating) during which excess emissions occur does not exceed:

(i) One percent for TRS emissions from recovery furnaces.

(ii) Six percent for average opacities from recovery furnaces.

(2) The Administrator determines that the affected facility, including air pollution control equipment, is maintained and operated in a manner which is consistent with good air pollution control practice for minimizing emissions during periods of excess emissions.

§ 60.285 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.282(a) as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) When determining compliance with § 60.282(a)(2), Method 2 for velocity and volumetric flow rate,

(4) Method 3 for gas analysis, and

(5) Method 9 for visible emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.85 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure outlined in Method 5.

(c) Method 17 (in-stack filtration) may be used as an alternate method for Method 5 for determining compliance with § 60.282(a)(1)(i): *Provided*, That a constant value of 0.009 g/dscm (0.004 gr/dscf) is added to the results of Method 17 and the stack temperature is no greater than 205° C (ca. 400° F). Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure outlined in Method 17.

(d) For the purpose of determining compliance with § 60.283(a) (1), (2), (3), (4), and (5), the following reference methods shall be used:

(1) Method 16 for the concentration of TRS,

(2) Method 3 for gas analysis, and

(3) When determining compliance with § 60.283(a)(4), use the results of Method 2, Method 16, and the black liquor solids feed rate in the following equation to determine the TRS emission rate.

$$E = (C_{H_2S}F_{H_2S} + C_{MeSH}F_{MeSH} + C_{DMS}F_{DMS} + C_{DMDS}F_{DMDS})(Q_{sd})/BLS$$

Where:

E = mass of TRS emitted per unity of black liquor solids (g/kg) (lb/ton)

C_{H_2S} = average concentration of hydrogen sulfide (H_2S) during the test period, PPM.

C_{MeSH} = average concentration of methyl mercaptan (MeSH) during the test period, PPM.

C_{DMS} = average concentration of dimethyl sulfide (DMS) during the test period, PPM.

C_{DMDS} = average concentration of dimethyl disulfide (DMDS) during the test period, PPM.

F_{H_2S} = 0.001417 g/m³ PPM for metric units
= 0.08844 lb/ft³ PPM for English units

F_{MeSH} = 0.00200 g/m³ PPM for metric units
= 0.1248 lb/ft³ PPM for English units

F_{DMS} = 0.002583 g/m³ PPM for metric units
= 0.1612 lb/ft³ PPM for English units

F_{DMDS} = 0.003917 g/m³ PPM for metric units
= 0.2445 lb/ft³ PPM for English units

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

BLS = black liquor solids feed rate, kg/hr (lb/hr)

(4) When determining whether a furnace is straight kraft recovery furnace or a cross recovery furnace, TAPPI Method T.624 shall be used to determine sodium sulfide, sodium hydroxide and sodium carbonate. These determinations shall be made three times daily from the green liquor and the daily average values shall be converted to sodium oxide (Na_2O) and substituted into the following equation to determine the green liquor sulfidity:

$$GLS = 100 \quad C_{Na_2S}/C_{Na_2S} + C_{NaOH} + C_{Na_2CO_3}$$

Where:

GLS = percent green liquor sulfidity

C_{Na_2S} = average concentration of Na_2S expressed as Na_2O (mg/1)

C_{NaOH} = *average concentration of NaOH* expressed as Na_2O (mg/1)

$C_{Na_2CO_3}$ = average concentration of Na_2CO_3 expressed as Na_2O (mg/1)

(e) All concentrations of particulate matter and TRS required to be measured by this section from lime kilns or incinerators shall be corrected 10 volume percent oxygen and those concentrations from recovery furnaces shall be corrected to 8 volume percent oxygen. These corrections shall be made in the manner specified in § 60.284(c)(3).

APPENDIX A—REFERENCE METHODS

(3) Method 16 and Method 17 are added to Appendix A as follows:

* * * * *

METHOD 16. SEMICONTINUOUS DETERMINATION OF SULFUR EMISSIONS FROM STATIONARY SOURCES

Introduction

The method described below uses the principle of gas chromatographic separation and flame photometric detection. Since there are many systems or sets of operating conditions that represent usable methods of determining sulfur emissions, all systems which employ this principle, but differ only in details of equipment and operation, may be used as alternative methods, provided that the criteria set below are met.

1. *Principle and Applicability.*

1.1 Principle. A gas sample is extracted from the emission source and diluted with clean dry air. An aliquot of the diluted sample is then analysed for hydrogen sulfide (H_2S), methyl mercaptan (MeSH), dimethyl sulfide (DMS) and dimethyl disulfide (DMDS) by gas chromatographic (GC) separation and flame photometric detection (FPD). These four compounds are known collectively as total reduced sulfur (TRS).

1.2 Applicability. This method is applicable for determination of TRS compounds from recovery furnaces, lime kilns, and smelt dissolving tanks at kraft pulp mills.

2. *Range and Sensitivity.*

2.1 Range. Coupled with a gas chromatographic system utilizing a ten milliliter sample size, the maximum limit of the FPD for each sulfur compound is approximately 1 ppm. This limit is expanded by dilution of the sample gas before analysis. Kraft mill gas samples are normally diluted tenfold (9:1), resulting in an upper limit of about 10 ppm for each compound.

For sources with emission levels between 10 and 100 ppm, the measuring range can be best extended by reducing the sample size to 1 milliliter.

2.2 Using the sample size, the minimum detectable concentration is approximately 50 ppb.

3. *Interferences.*

3.1 Moisture Condensation. Moisture condensation in the sample delivery system, the analytical column, or the FPD burner block can cause losses or interferences. This potential is eliminated by heating the sample line, and by conditioning the sample with dry dilution air to lower its dew point below the operating temperature of the GC/FPD analytical system prior to analysis.

3.2 Carbon Monoxide and Carbon Dioxide. CO and CO_2 have substantial desensitizing effect on the flame photometric detector even after 9:1 dilution. Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluting these compounds before any of the compounds to be measured. Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without CO_2 in the diluent gas. The CO_2 level should be approximately 10 percent for the case with CO_2 present. The two chromatographs should show agreement within the precision limits of Section 4.1.

3.3 Particulate Matter. Particulate matter in gas samples can cause interference by eventual clogging of the analytical system. This interference must be eliminated by use of a probe filter.

3.4 Sulfur Dioxide. SO_2 is not a specific interferent but may be present in such large amounts that it cannot be effectively separated from other compounds of interest. The procedure must be designed to eliminate this problem either by the choice of separation columns or by removal of SO_2 from the sample.

Compliance with this section can be demonstrated by submitting chromatographs of calibration gases with SO_2 present in the same quantities expected from the emission source to be tested. Acceptable systems shall show baseline separation with the amplifier attenuation set so that the reduced sulfur compound of concern is at least 50 percent of full scale. Base line separation is defined as a return to zero ± percent in the interval between peaks.

4. *Precision and Accuracy.*

4.1 GC/FPD and Dilution System Calibration Precision. A series of three consecutive injections of the same calibration gas, at any dilution, shall produce results which do not vary by more than ±3 percent from the mean of the three injections.

4.2 GC/FPD and Dilution System Calibration Drift. The calibration drift determined from the mean of three injections made at the beginning and end of any 8-hour period shall not exceed ± percent.

4.3 System Calibration Accuracy. The complete system must quantitatively transport and analyse with an accuracy of 20 percent. A correction factor is developed to adjust calibration accuracy to 100 percent.

5. *Apparatus* (See Figure 16–1).

5.1.1 Probe. The probe must be made of inert material such as stainless steel or glass. It should be designed to incorporate a filter and to allow calibration gas to enter the probe at or near the sample entry point. Any portion of the probe not exposed to the stack gas must be heated to prevent moisture condensation.

5.1.2 Sample Line. The sample line must be made of Teflon,[1] no greater than 1.3 cm (½) inside diameter. All parts from the probe to the dilution system must be thermostatically heated to 120° C.

5.1.3 Sample Pump. The sample pump shall be a leakless Teflon-coated diaphragm type or equivalent. If the pump is upstream of the dilution system, the pump head must be heated to 120° C.

5.2 Dilution System. The dilution system must be constructed such that all sample contacts are made of inert materials (e.g., stainless steel or Teflon). It must be heated to 120° C. and be capable of approximately a 9:1 dilution of the sample.

5.3 Gas Chromatograph. The gas chromatograph must have at least the following components:

5.3.1 Oven. Capable of maintaining the separation column at the proper operating temperature ±1° C.

5.3.2 Temperature Gauge. To monitor column oven, detector, and exhaust temperature ±1° C.

5.3.3 Flow System. Gas metering system to measure sample, fuel, combustion gas, and carrier gas flows.

5.3.4 Flame Photometric Detector.

5.3.4.1 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

5.3.4.2 Power Supply. Capable of delivering up to 750 volts.

5.3.4.3 Recorder. Compatible with the output voltage range of the electrometer.

5.4 Gas Chromatograph Columns. The column system must be demonstrated to be capble of resolving the four major reduced sulfur compounds: H_2S, MeSH, DMS, and DMDS. It must also demonstrate freedom from known interferences.

To demonstrate that adequate resolution has been achieved, the tester must submit a chromatograph of a calibration gas containing all four of the TRS compounds in the concentration range of the applicable standard. Adequate resolution will be defined as base line separation of adjacent peaks when the amplifier attenuation is set so that the smaller peak is at least 50 percent of full scale. Base line separation is defined in Section 3.4. Systems not meeting this criteria may be considered alternate methods subject to the approval of the Administrator.

5.5. Calibration System. The calibration system must contain the following components.

5.5.1 Tube Chamber. Chamber of glass or Teflon of sufficient dimensions to house permeation tubes.

5.5.2 Flow System. To measure air flow over permeation tubes at ±2 percent. Each flowmeter shall be calibrated after a complete test series with a wet test meter. If the flow measuring device differs from the wet test meter by 5 percent, the completed test shall be discarded. Alternatively, the tester may elect to use the flow data that would yield the lowest flow measurement. Calibration with a wet test meter before a test is optional.

5.5.3 Constant Temperature Bath. Device capable of maintaining the permeation tubes at the calibration temperature within ±0.1° C.

5.5.4 Temperature Gauge. Thermometer or equivalent to monitor bath temperature within ±1° C.

6. *Reagents.*

6.1 Fuel. Hydrogen (H_2) prepurified grade or better.

6.2 Combustion Gas. Oxygen (O_2) or air, research purity or better.

6.3 Carrier Gas. Prepurified grade or better.

6.4 Diluent. Air containing less than 50 ppb total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons. This gas must be heated prior to mixing with the sample to avoid water condensation at the point of contact.

6.5 Calibration Gases. Permeation tubes, one each of H_2S, MeSH, DMS, and DMDS, agravimetrically calibrated and certified at some convenient operating temperature. These tubes consist of hermetically sealed FEP Teflon tubing in which a liquified gaseous substance is enclosed. The enclosed gas permeates through the tubing wall at a constant rate. When the temperature is constant, calibration gases covering a wide range of known concentrations can be generated by varying and accurately measuring the flow rate of diluent gas passing over the tubes. These calibration gases are used to calibrate the GC/FPD system and the dilution system.

7. *Pretest Procedures.* The following procedures are optional but would be helpful in preventing any problem which might occur later and invalidate the entire test.

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[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

7.1 After the complete measurement system has been set up at the site and deemed to be operational, the following procedures should be completed before sampling is initiated.

7.1.1 Leak Test. Appropriate leak test procedures should be employed to verify the integrity of all components, sample lines, and connections. The following leak test procedure is suggested: For components upstream of the sample pump, attach the probe end of the sample line to a manometer or vacuum gauge, start the pump and pull greater than 50 mm (2 in.) Hg vacuum, close off the pump outlet, and then stop the pump and ascertain that there is no leak for 1 minute. For components after the pump, apply a slight positive pressure and check for leaks by applying a liquid (detergent in water, for example) at each joint. Bubbling indicates the presence of a leak.

7.1.2 System Performance. Since the complete system is calibrated following each test, the precise calibration of each component is not critical. However, these components should be verified to be operating properly. This verification can be performed by observing the response of flowmeters or of the GC output to changes in flow rates or calibration gas concentrations and ascertaining the response to be within predicted limits. In any component, or if the complete system fails to respond in a normal and predictable manner, the source of the discrepancy should be identified and corrected before proceeding.

8. *Calibration.* Prior to any sampling run, calibrate the system using the following procedures. (If more than one run is performed during any 24-hour period, a calibration need not be performed prior to the second and any subsequent runs. The calibration must, however, be verified as prescribed in Section 10, after the last run made within the 24-hour period.)

8.1 General Considerations. This section outlines steps to be followed for use of the GC/FPD and the dilution system. The procedure does not include detailed instructions because the operation of these systems is complex, and it requires a understanding of the individual system being used. Each system should include a written operating manual describing in detail the operating procedures associated with each component in the measurement system. In addition, the operator should be familiar with the operating principles of the components; particularly the GC/FPD. The citations in the Bibliography at the end of this method are recommended for review for this purpose.

8.2 Calibration Procedure. Insert the permeation tubes into the tube chamber. Check the bath temperature to assure agreement with the calibration temperature of the tubes within ±0.1° C. Allow 24 hours for the tubes to equilibrate. Alternatively equilibration may be verified by injecting samples of calibration gas at 1-hour intervals. The permeation tubes can be assumed to have reached equilibrium when consecutive hourly samples agree within the precision limits of Section 4.1.

Vary the amount of air flowing over the tubes to produce the desired concentrations for calibrating the analytical and dilution systems. The air flow across the tubes must at all times exceed the flow requirement of the analytical systems. The concentration in parts per million generated by a tube containing a specific permeant can be calculated as follows:

$$C = K \frac{P_r}{ML}$$

Equation 16-1

where:

C = Concentration of permeant produced in ppm.

P_r = Permeation rate of the tube in μg/min.

M = Molecular weight of the permeant (g/g-mole).

L = Flow rate, 1/min, of air over permeant @ 20° C, 760 mm Hg.

K = Gas constant at 20° C and 760 mm Hg = 24.04 1/g mole.

8.3 Calibration of analysis system. Generate a series of three or more known concentrations spanning the linear range of the FPD (approximately 0.05 to 1.0 ppm) for each of the four major sulfur compounds. Bypassing the dilution system, inject these standards into the GC/FPD analyzers and monitor the responses. Three injects for each concentration must yield the precision described in Section 4.1. Failure to attain this precision is an indication of a problem in the calibration or analytical system. Any such problem must be identified and corrected before proceeding.

8.4 Calibration Curves. Plot the GC/FPD response in current (amperes) versus their causative concentrations in ppm on log-log coordinate graph paper for each sulfur compound. Alternatively, a least squares equation may be generated from the calibration data.

8.5 Calibration of Dilution System. Generate a known concentration of hydrogen sulfide using the permeation tube system. Adjust the flow rate of diluent air for the first dilution stage so that the desired level of dilution is approximated. Inject the diluted calibration gas into the GC/FPD system and monitor its response. Three injections for each dilution must yield the precision described in Section 4.1. Failure to attain this precision in this step is an indication of a problem in the dilution system. Any such problem must be identified and corrected before proceeding. Using the calibration data for H_2S (developed under 8.3) determine the diluted calibration gas concentration in ppm. Then calculate the dilution factor as the ratio of the calibration gas concentration before dilution to the diluted calibration gas concentration determined under this paragraph. Repeat this procedure for each stage of dilution required. Alternatively, the GC/FPD system may be calibrated by generating a series of three or more concentrations of each sulfur compound and diluting these samples before injecting them into the GC/FPD system. This data will then serve as the calibration data for the unknown samples and a separate determination of the dilution factor will not be necessary. However, the precision requirements of Section 4.1 are still applicable.

9. *Sampling and Analysis Procedure.*

9.1 Sampling. Insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Begin sampling and dilute the sample approximtely 9:1 using the dilution system. Note that the precise dilution factor is that which is determined in paragraph 8.5. Condition the entire system with sample for a minimum of 15 minutes prior to commencing analysis.

9.2 Analysis. Aliquots of diluted sample are injected into the GC/FPD analyzer for analysis.

9.2.1 Sample Run. A sample run is composed of 16 individual analyses (injects) performed over a period of not less than 3 hours or more than 6 hours.

9.2.2 Observation for Clogging of Probe. If reductions in sample concentrations are observed during a sample run that cannot be explained by process conditions, the sampling must be interrupted to determine if the sample probe is clogged with particulate matter. If the probe is found to be clogged, the test must be stopped and the results up to that point discarded. Testing may resume after cleaning the probe or replacing it with a clean one. After each run, the sample probe must be inspected and, if necessary, dismantled and cleaned.

10. *Post-Test Procedures.*

10.1 Sample Line Loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ±20 percent, must be introduced into the sampling system at the opening of the probe in sufficient quantities to insure that there is an excess of sample which must be vented to the atmosphere. The sample must be transported through the entire sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss. A sampling system loss of more than 20 percent is unacceptable. Sampling losses of 0-20 percent must be corrected for by dividing the resulting sample concentration by the fraction of recovery. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.

10.2 Recalibration. After each run, or after a series of runs made within a 24-hour period, perform a partial recalibration using the procedures in Section 8. Only H_2S (or other permeant) need be used to recalibrate the GC/FPD analysis system (8.3) and the dilution system (8.5).

10.3 Determination of Calibration Drift. Compare the calibration curves obtained prior to the runs, to the calibration curves obtained under paragraph 10.1. The calibration drift should not exceed the limits set forth in paragraph 4.2. If the drift exceeds this limit, the intervening run or runs should be considered not valid. The tester, however, may instead have the option of choosing the calibration data set which would give the highest sample values.

11. *Calculations.*

11.1 Determine the concentrations of each reduced sulfur compound detected directly from the calibration curves. Alternatively, the concentrations may be calculated using the equation for the least square line.

11.2 Calculation of TRS. Total reduced sulfur will be determined for each anaylsis made by summing the concentrations of each reduced sulfur compound resolved during a given analysis.

$$TRS = \Sigma\,(H_2S,\ MeSH,\ DMS,\ 2DMDS)d$$

Equation 16-2

where:

TRS = Total reduced sulfur in ppm, wet basis.

H_2S = Hydrogen sulfide, ppm.

MeSH = Methyl mercaptan, ppm.

DMS = Dimethyl sulfide, ppm.

DMDS = Dimethyl disulfide, ppm.

d = Dilution factor, dimensionless.

11.3 Average TRS. The average TRS will be determined as follows:

$$\text{Average TRS} = \frac{\sum_{i=1}^{N} TRS_i}{N(1-B_{wo})}$$

Average TRS = Average total reduced suflur in ppm, dry basis.
TRS_i = Total reduced sulfur in ppm as determined by Equation 16-2.
N = Number of samples.
B_{wo} = Fraction of volume of water vapor in the gas stream as determined by method 4—Determination of Moisture in Stack Gases (36 FR 24887).

11.4 Average concentration of individual reduced sulfur compounds.

$$C = \frac{\sum_{i=1}^{N} S_i}{N}$$

Equation 16-3

where:

S_i = Concentration of any reduced sulfur compound from the ith sample injection, ppm.
C = Average concentration of any one of the reduced sulfur compounds for the entire run, ppm.
N = Number of injections in any run period.

12. *Example System.* Described below is a system utilized by EPA in gathering NSPS data. This system does not now reflect all the latest developments in equipment and column technology, but it does represent one system that has been demonstrated to work.

12.1 Apparatus.

12.1.1 Sampling System.

12.1.1.1 Probe. Figure 16-1 illustrates the probe used in lime kilns and other sources where significant amounts of particulate matter are present, the probe is designed with the deflector shield placed between the sample and the gas inlet holes and the glass wool plugs to reduce clogging of the filter and possible adsorption of sample gas. The exposed portion of the probe between the sampling port and the sample line is heated with heating tape.

12.1.1.2 Sample Line 3/16 inch inside diameter Teflon tubing, heated to 120° C. This temperature is controlled by a thermostatic heater.

12.1.1.3 Sample Pump. Leakless Teflon coated diaphragm type or equivalent. The pump head is heated to 120° C by enclosing it in the sample dilution box (12.2.4 below).

12.1.2 Dilution System. A schematic diagram of the dynamic dilution system is given in Figure 16-2. The dilution system is constructed such that all sample contacts are made of inert materials. The dilution system which is heated to 120° C must be capable of a minimum of 9:1 dilution of sample. Equipment used in the dilution system is listed below:

12.1.2.1 Dilution Pump. Model A-150 Kohmyhr Teflon positive displacement type, nonadjustable 150 cc/min. ±2.0 percent, or equivalent, per dilution stage. A 9:1 dilution of sample is accomplished by combining 150 cc of sample with 1,350 cc of clean dry air as shown in Figure 16-2.

12.1.2.2 Valves. Three-way Teflon solenoid or manual type.

12.1.2.3 Tubing. Teflon tubing and fittings are used throughout from the sample probe to the GC/FPD to present an inert surface for sample gas.

12.1.2.4 Box. Insulated box, heated and maintained at 120° C, of sufficient dimensions to house dilution apparatus.

12.1.2.5 Flowmeters. Rotameters or equivalent to measure flow from 0 to 1500 ml/min ±1 percent per dilution stage.

12.1.3 Gas Chromatograph Columns. Two types of columns are used for separation of low and high molecular weight sulfur compounds:

12.1.3.1 Low Molecular Weight Sulfur Compounds Column (GC/FPD-1).

12.1.3.1 Separation Column. 11 m by 2.16 mm (36 ft by 0.085 in) inside diameter Teflon tubing packed with 30/60 mesh Teflon coated with 5 percent polyphenyl ether and 0.05 percent orthophosphoric acid, or equivalent (see Figure 16-3).

12.1.3.1.2 Stripper or Precolumn. 0.6 m by 2.16 mm (2 ft by 0.085 in) inside diameter Teflon tubing packed as in 5.3.1.

12.1.3.1.3 Sample Valve. Teflon 10-port gas sampling valve, equipped with a 10 ml sample loop, actuated by compressed air (Figure 16-3).

12.1.3.1.4 Oven. For containing sample valve, stripper column and separation column. The oven should be capable of maintaining an elevated temperature ranging from ambient to 100° C, constant within ±1° C.

12.1.3.1.5 Temperature Monitor. Thermocouple pyrometer to measure column oven, detector, and exhaust temperature ±1° C.

12.1.3.1.6 Flow System. Gas metering system to measure sample flow, hydrogen flow, and oxygen flow (and nitrogen carrier gas flow).

12.1.3.1.7 Detector. Flame photometric detector.

12.1.3.1.8 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

12.1.3.1.9 Power Supply. Capable of delivering up to 750 volts.

12.1.3.1.10 Recorder. Compatible with the output voltage range of the electrometer.

12.1.3.2 High Molecular Weight Compounds Column (GC/FPD-11).

12.1.3.2.1. Separation Column. 3.05 m by 2.16 mm (10 ft by 0.0885 in) inside diameter Teflon tubing packed with 30/60 mesh Teflon coated with 10 percent Triton X-305, or equivalent.

12.1.3.2.2 Sample Valve. Teflon 6-port gas sampling valve equipped with a 10 ml sample loop, actuated by compressed air (Figure 16-3).

12.1.3.2.3 Other Components. All components same as in 12.1.3.1.4 to 12.1.3.1.10.

12.1.4 Calibration. Permeation tube system (figure 16-4).

12.1.4.1 Tube Chamber. Glass chamber of sufficient dimensions to house permeation tubes.

12.1.4.2 Mass Flowmeters. Two mass flowmeters in the range 0-3 1/min. and 0-10 1/min. to measure air flow over permeation tubes at ±2 percent. These flowmeters shall be cross-calibrated at the beginning of each test. Using a convenient flow rate in the measuring range of both flowmeters, set and monitor the flow rate of gas over the permeation tubes. Injection of calibration gas generated at this flow rate as measured by one flowmeter followed by injection of calibration gas at the same flow rate as measured by the other flowmeter should agree within the specified precision limits. If they do not, then there is a problem with the mass flow measurement. Each mass flowmeter shall be calibrated prior to the first test with a wet test meter and thereafter, at least once each year.

12.1.4.3 Constant Temperature Bath. Capable of maintaining permeation tubes at certification temperature of 30° C. within ±0.1° C.

12.2 Reagents

12.2.1 Fuel. Hydrogen (H_2) prepurified grade or better.

12.2.2. Combustion Gas. Oxygen (O_2) research purity or better.

12.2.3 Carrier Gas. Nitrogen (N_2) prepurified grade or better.

12.2.4 Diluent. Air containing less than 50 ppb total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons, and filtered using MSA filters 46727 and 79030, or equivalent. Removal of sulfur compounds can be verified by injecting dilution air only, described in Section 8.3.

12.2.5 Compressed Air. 60 psig for GC valve actuation.

12.2.6 Calibrated Gases. Permeation tubes gravimetrically calibrated and certified at 30.0° C.

12.3 Operating Parameters.

12.3.1 Low-Molecular Weight Sulfur Compounds. The operating parameters for the GC/FPD system used for low molecular weight compounds are as follows: nitrogen carrier gas flow rate of 50 cc/min, exhaust temperature of 110° C, detector temperature of 105° C, oven temperature of 40° C, hydrogen flow rate of 80 cc/min, oxygen flow rate of 20 cc/min, and sample flow rate between 20 and 80 cc/min.

12.3.2 High-Molecular Weight Sulfur Compounds. The operating parameters for the GC/FPD system for high molecular weight compounds are the same as in 12.3.1 except: oven temperature of 70° C, and nitrogen carrier gas flow of 100 cc/min.

12.4 Analysis Procedure.

12.4.1 Analysis. Aliquots of diluted sample are injected simultaneously into both GC/FPD analyzers for analysis. GC/FPD-I is used to measure the low-molecular weight reduced sulfur compounds. The low molecular weight compounds include hydrogen sulfide, methyl mercaptan, and dimethyl sulfide. GC/FPD-II is used to resolve the high-molecular weight compound. The high-molecular weight compound is dimethyl disulfide.

12.4.1.1 Analysis of Low-Molecular Weight Sulfur Compounds. The sample valve is actuated for 3 minutes in which time an aliquot of diluted sample is injected into the stripper column and analytical column. The valve is then deactivated for approximately 12 minutes in which time, the analytical column continues to be foreflushed, the stripper column is backflushed, and the sample loop is refilled. Monitor the responses. The elution time for each compound will be determined during calibration.

12.4.1.2 Analysis of High-Molecular Weight Sulfur Compounds. The procedure is essentially the same as above except that no stripper column is needed.

13. *Bibliography.*

13.1 O'Keeffe, A. E. and G. C. Ortman. "Primary Standards for Trace Gas Analy-

sis." Analytical Chemical Journal, 38,760 (1966).

13.2 Stevens, R. K., A. E. O'Keeffe, and G. C. Ortman. "Absolute Calibration of a Flame Photometric Detector to Volatile Sulfur Compounds at Sub-Part-Per-Million Levels." Environmental Science and Technology, 3:7 (July, 1969).

13.3 Mulick, J. D., R. K. Stevens, and R. Baumgardner. "An Analytical System Designed to Measure Multiple Malodorous Compounds Related to Kraft Mill Activities." Presented at the 12th Conference on Methods in Air Pollution and Industrial Hygiene Studies, University of Southern California, Los Angeles, CA. April 6-8, 1971.

13.4 Devonald, R. H., R. S. Serenius, and A. D. McIntyre. "Evaluation of the Flame Photometric Detector for Analysis of Sulfur Compounds." Pulp and Paper Magazine of Canada, 73,3 (March, 1972).

13.5 Grimley, K. W., W. S. Smith, and R. M. Martin. "The Use of a Dynamic Dilution System in the Conditioning of Stack Gases for Automated Analysis by a Mobile Sampling Van." Presented at the 63rd Annual APCA Meeting in St. Louis, Mo. June 14-19, 1970.

13.6 General Reference. Standard Methods of Chemical Analysis Volume III A and B Instrumental Methods. Sixth Edition. Van Nostrand Reinhold Co.

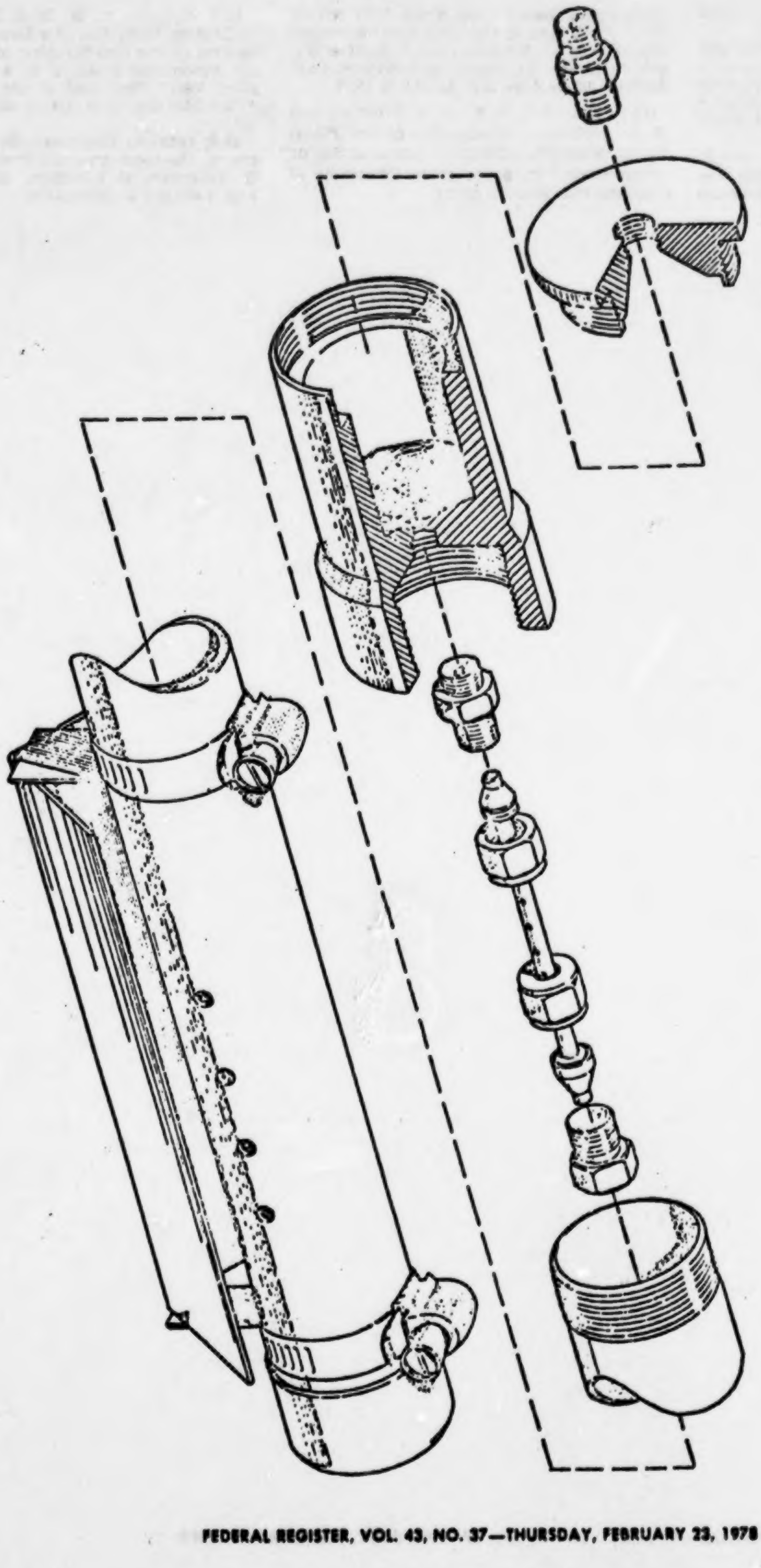


Figure 16-1. Probe used for sample gas containing high particulate loadings.

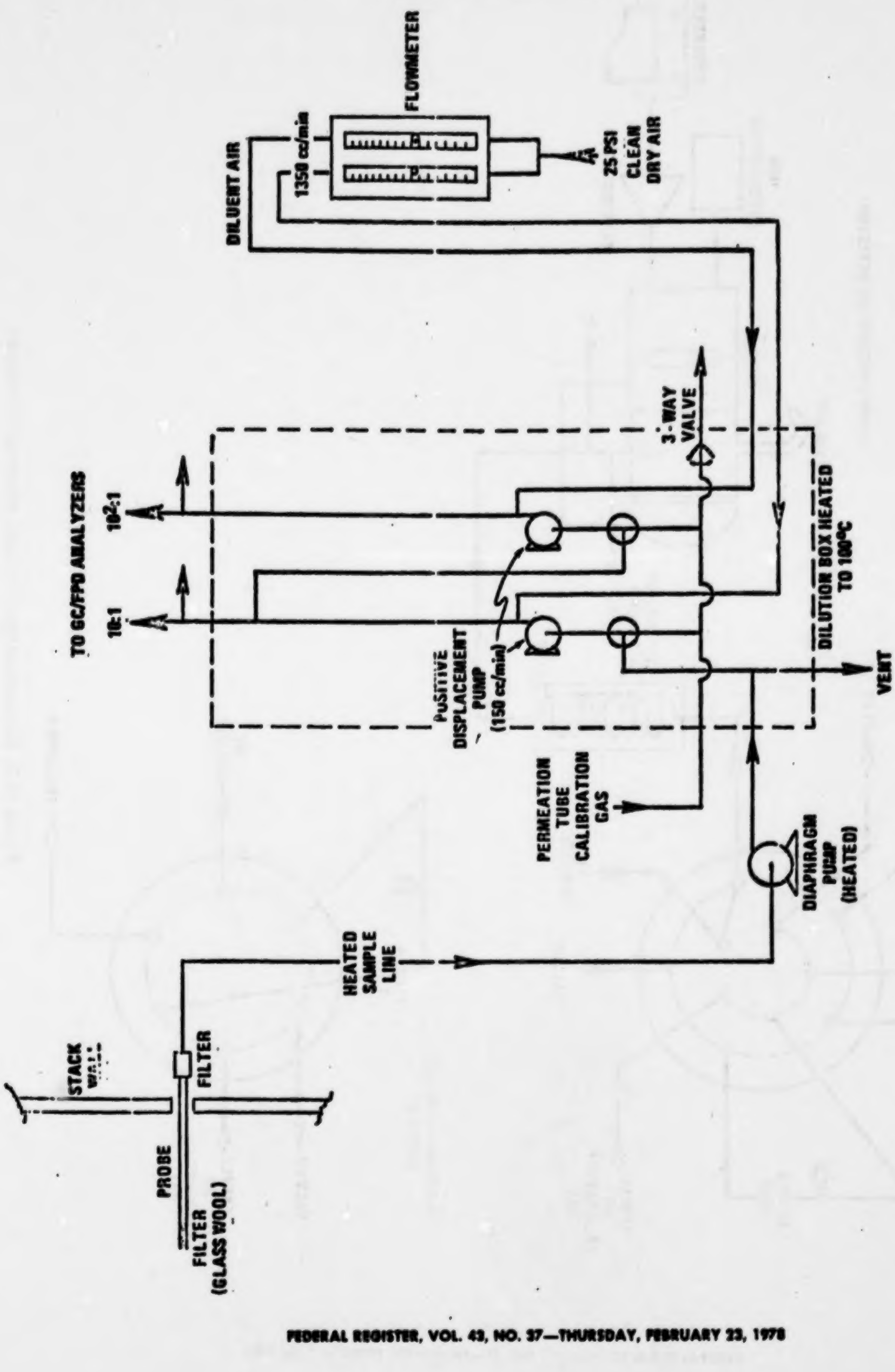

STACK WALL
PROBE
FILTER (GLASS WOOL)
FILTER
HEATED SAMPLE LINE
DIAPHRAGM PUMP (HEATED)
PERMEATION TUBE CALIBRATION GAS
POSITIVE DISPLACEMENT PUMP (150 cc/min)
VENT
DILUTION BOX HEATED TO 100°C
TO GC/FPD ANALYZERS
10:1
10²:1
3-WAY VALVE
DILUENT AIR
1350 cc/min
FLOWMETER
25 PSI CLEAN DRY AIR

Figure 16-2. Sampling and dilution apparatus.

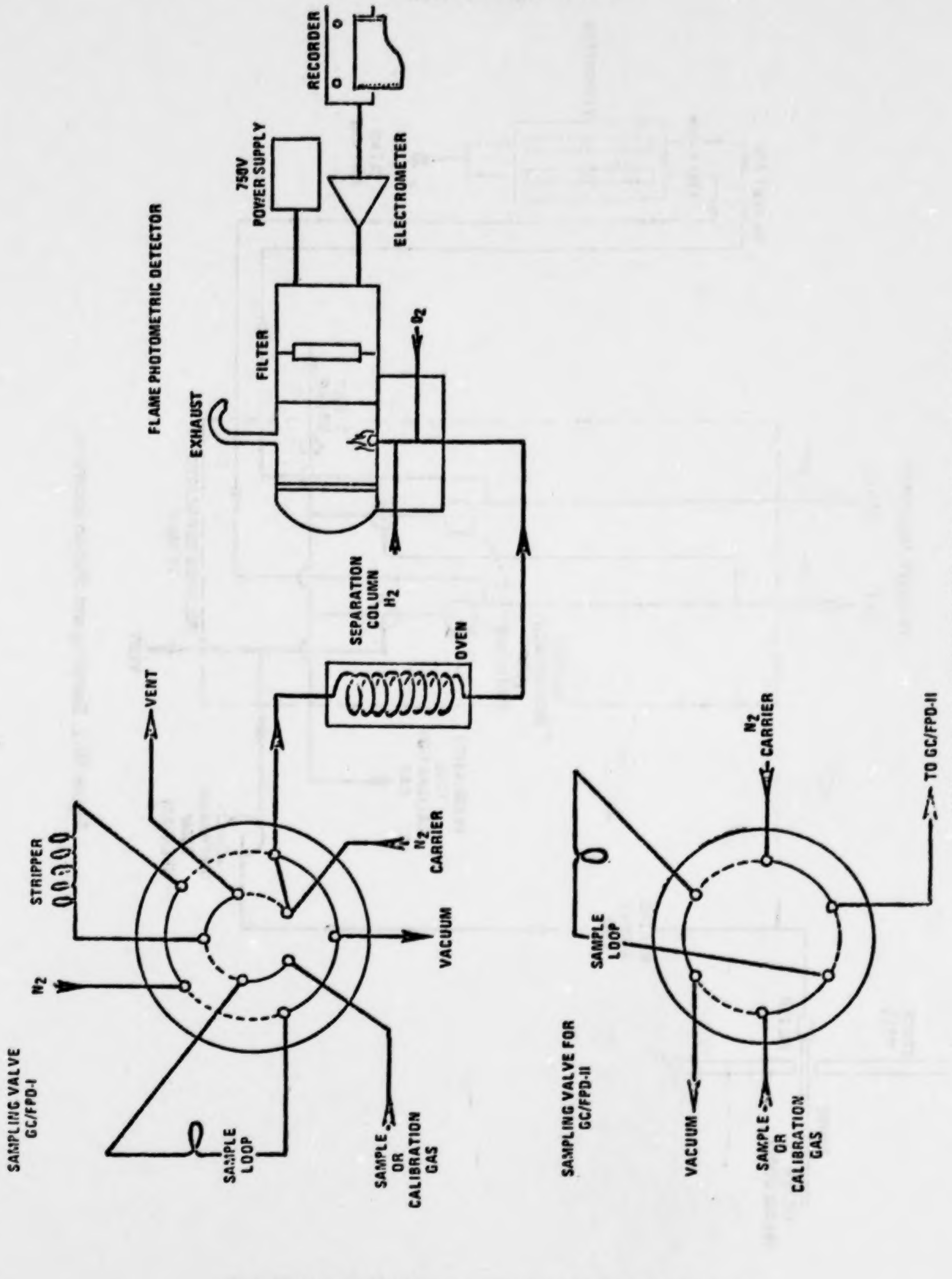

SAMPLING VALVE GC/FPD-I
N2
STRIPPER
VENT
N2 CARRIER
VACUUM
SAMPLE LOOP
SAMPLE OR CALIBRATION GAS
SEPARATION COLUMN
H2
OVEN
FLAME PHOTOMETRIC DETECTOR
EXHAUST
FILTER
O2
750V POWER SUPPLY
ELECTROMETER
RECORDER
SAMPLING VALVE FOR GC/FPD-II
N2 CARRIER
TO GC/FPD-II
SAMPLE LOOP
VACUUM
SAMPLE OR CALIBRATION GAS

Figure 16-3. Gas chromatographic-flame photometric analyzers.

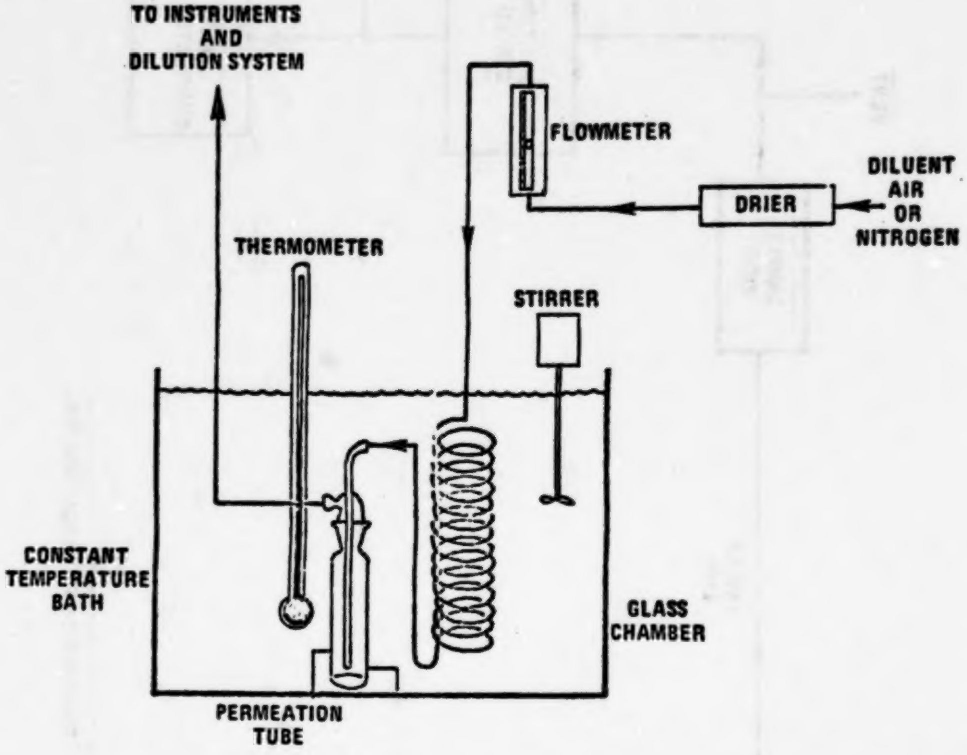

TO INSTRUMENTS AND DILUTION SYSTEM
FLOWMETER
DILUENT AIR OR NITROGEN
DRIER
THERMOMETER
STIRRER
CONSTANT TEMPERATURE BATH
GLASS CHAMBER
PERMEATION TUBE

Figure 16-4. Apparatus for field calibration.

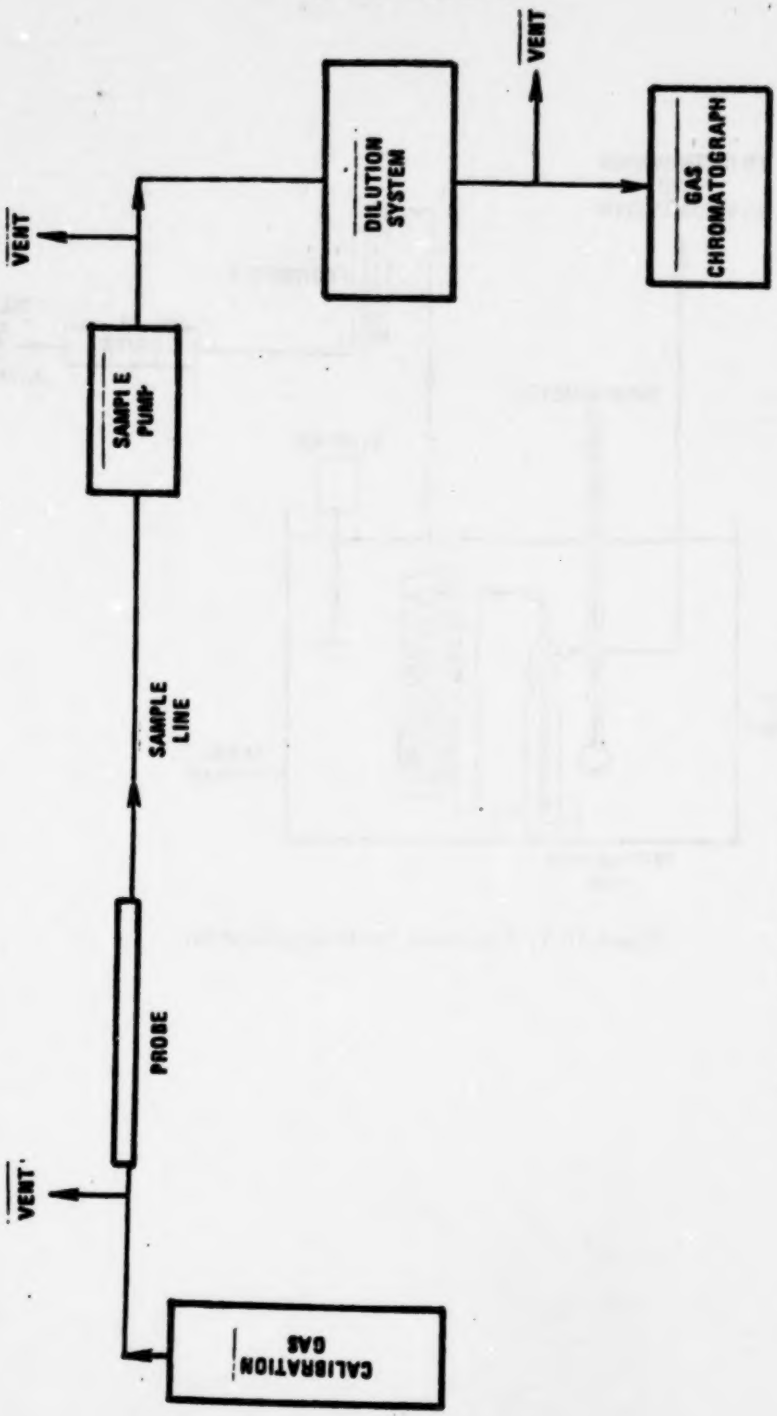

CALIBRATION GAS
VENT
PROBE
SAMPLE LINE
SAMPLE PUMP
VENT
DILUTION SYSTEM
VENT
GAS CHROMATOGRAPH

Figure 16-5. Determination of sample line loss.

METHOD 17. DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES (IN-STACK FILTRATION METHOD)

Introduction

Particulate matter is not an absolute quantity; rather, it is a function of temperature and pressure. Therefore, to prevent variability in particulate matter emission regulations and/or associated test methods, the temperature and pressure at which particulate matter is to be measured must be carefully defined. Of the two variables (i.e., temperature and pressure), temperature has the greater effect upon the amount of particulate matter in an effluent gas stream; in most stationary source categories, the effect of pressure appears to be negligible.

In method 5, 250° F is established as a nominal reference temperature. Thus, where Method 5 is specified in an applicable subpart of the standards, particulate matter is defined with respect to temperature. In order to maintain a collection temperature of 250° F, Method 5 employs a heated glass sample probe and a heated filter holder. This equipment is somewhat cumbersome and requires care in its operation. Therefore, where particulate matter concentrations (over the normal range of temperature associated with a specified source category) are known to be independent of temperature, it is desirable to eliminate the glass probe and heating systems, and sample at stack temperature.

This method describes an in-stack sampling system and sampling procedures for use in such cases. It is intended to be used only when specified by an applicable subpart of the standards, and only within the applicable temperature limits (if specified), or when otherwise approved by the Administrator.

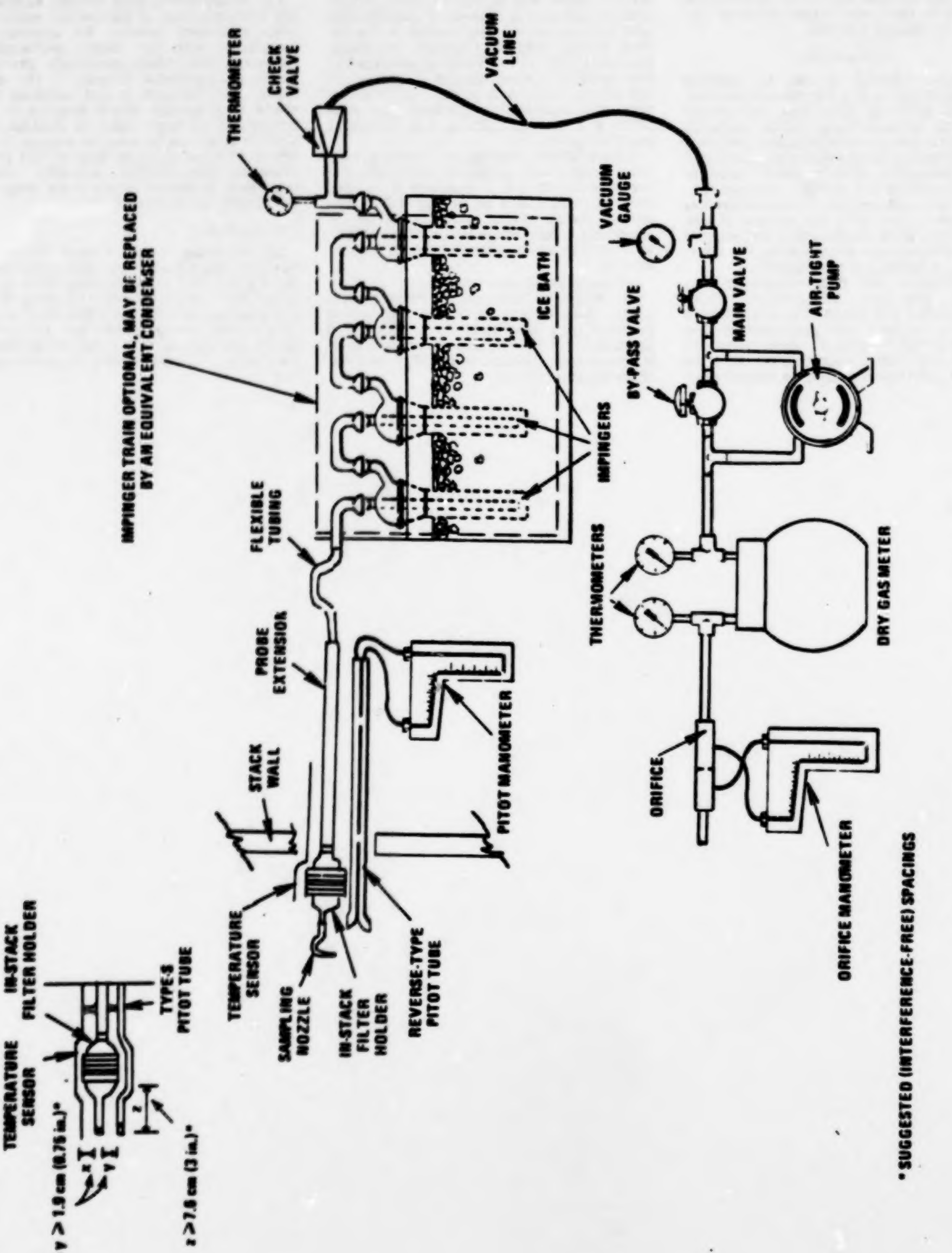
1. *Principle and Applicability.*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at stack temperature. The particulate mass is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method applies to the determination of particulate emissions from stationary sources for determining compliance with new source performance standards, only when specifically provided for in an applicable subpart of the standards. This method is not applicable to stacks that contain liquid droplets or are saturated with water vapor. In addition, this method shall not be used as written if the projected cross-sectional area of the probe extension-filter holder assembly covers more than 5 percent of the stack cross-sectional area (see Section 4.1.2).

2. *Apparatus.*

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 17-1. Construction details for many, but not all, of the train components are given in APTD-0581 (Citation 2 in Section 7); for changes from the APTD-0581 document and for allowable modifications to Figure 17-1, consult with the Administrator.


THERMOMETER
CHECK VALVE
VACUUM LINE
IMPINGER TRAIN OPTIONAL, MAY BE REPLACED BY AN EQUIVALENT CONDENSER
ICE BATH
VACUUM GAUGE
MAIN VALVE
AIR-TIGHT PUMP
BY-PASS VALVE
IMPINGERS
FLEXIBLE TUBING
THERMOMETERS
DRY GAS METER
PROBE EXTENSION
PITOT MANOMETER
STACK WALL
ORIFICE
ORIFICE MANOMETER
TEMPERATURE SENSOR
SAMPLING NOZZLE
IN-STACK FILTER HOLDER
REVERSE-TYPE PITOT TUBE
IN-STACK FILTER HOLDER
TYPE-S PITOT TUBE
TEMPERATURE SENSOR
x
y
z
x - y > 1.9 cm (0.75 in.)*
z > 7.6 cm (3 in.)*

*SUGGESTED (INTERFERENCE-FREE) SPACINGS

Figure 17-1. Particulate-Sampling Train, Equipped with In-Stack Filter.

The operating and maintenance procedures for many of the sampling train components are described in APTD-0576 (Citation 3 in Section 7). Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass, with sharp, tapered leading edge. The angle of taper shall be 030° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing. Other materials of construction may be used subject to the approval of the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm ($\frac{1}{8}$ to $\frac{1}{2}$ in)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm ($\frac{1}{16}$ in). Each nozzle shall be calibrated according to the procedures outlined in Section 5.1.

2.1.2 Filter Holder. The in-stack filter holder shall be constructed of borosilicate or quartz glass, or stainless steel; if a gasket is used, it shall be made of silicone rubber, Teflon, or stainless steel. Other holder and gasket materials may be used subject to the approval of the Administrator. The filter holder shall be designed to provide a positive seal against leakage from the outside or around the filter.

2.1.3 Probe Extension. Any suitable rigid probe extension may be used after the filter holder.

2.1.4 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator; the pitot tube shall be attached to the probe extension to allow constant monitoring of the stack gas velocity (see Figure 17-1). The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane during sampling (see Method 2, Figure 2-6b). It is recommended: (1) that the pitot tube have a known baseline coefficient, determined as outlined in Section 4 of Method 2; and (2) that this known coefficient be preserved by placing the pitot tube in an interference-free arrangement with respect to the sampling nozzle, filter holder, and temperature sensor (see Figure 17-1). Note that the 1.9 cm (0.75 in) free-space between the nozzle and pitot tube shown in Figure 17-1, is based on a 1.3 cm (0.5 in) ID nozzle. If the sampling train is designed for sampling at higher flow rates than that described in APTD-0581, thus necessitating the use of larger sized nozzles, the free-space shall be 1.9 cm (0.75 in) with the largest sized nozzle in place.

Source-sampling assemblies that do not meet the minimum spacing requirements of Figure 17-1 (or the equivalent of these requirements, e.g., Figure 2-7 of Method 2) may be used; however, the pitot tube coefficients of such assemblies shall be determined by calibration, using methods subject to the approval of the Administrator.

2.1.5 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.6 Condenser. It is recommended that the impinger system described in Method 5 be used to determine the moisture content of the stack gas. Alternatively, any system that allows measurement of both the water condensed and the moisture leaving the condenser, each to within 1 ml or 1 g, may be used. The moisture leaving the condenser can be measured either by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a silica gel trap with exit gases kept below 20° C (68° F) and determining the weight gain.

Flexible tubing may be used between the probe extension and condenser. If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.7 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 17-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.8 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.9 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3.

The temperature sensor shall be attached to either the pitot tube or to the probe extension, in a fixed configuration. If the temperature sensor is attached in the field; the sensor shall be placed in an interference-free arrangement with respect to the Type S pitot tube openings (as shown in Figure 17-1 or in Figure 2-7 of Method 2). Alternatively, the temperature sensor need not be attached to either the probe extension or pitot tube during sampling, provided that a difference of not more than 1 percent in the average velocity measurement is introduced. This alternative is subject to the approval of the Administrator.

2.2 Sample Recovery.

2.2.1 Probe Nozzle Brush. Nylon bristle brush with stainless steel wire handle. The brush shall be properly sized and shaped to brush out the probe nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples; glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethylene, to aid in sample recovery.

2.3 Analysis.

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 mg.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. *Reagents.*

3.1 Sampling.

3.1.1 Filters. The in-stack filters shall be glass mats or thimble fiber filters, without organic binders, and shall exhibit at least 99.95 percent efficiency (00.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles. The filter efficiency tests shall be conducted in accordance with ASTM standard method D 2986-71. Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2 Silica Gel. Indicating type, 6- to 16-mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Crushed Ice.

3.1.4 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone, reagent grade, 00.001 percent residue, in glass bottles. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers. Thus, acetone blanks shall be run prior to field use and only acetone with low blank values (00.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis.

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. *Procedure.*

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

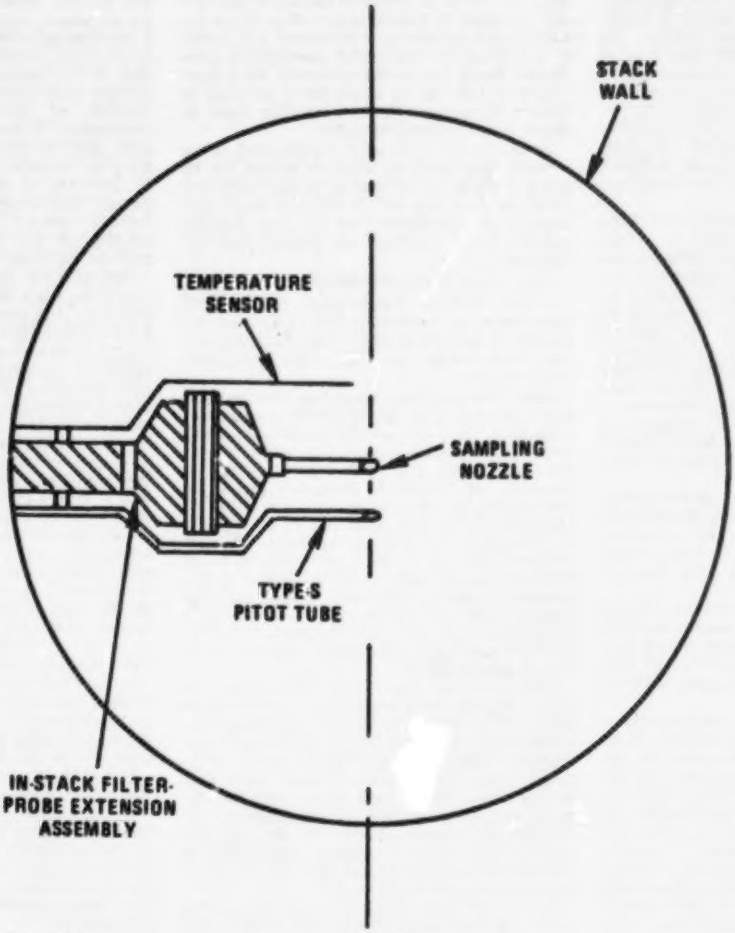
4.1.1 Pretest Preparation. All components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper size on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., 00.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Make a projected-area model of the probe extension-filter holder assembly, with the pitot tube face openings positioned along the centerline of the stack, as shown in Figure 17-2. Calculate the estimated cross-section blockage, as shown in Figure 17-2. If the blockage exceeds 5 percent of the duct cross sectional area, the tester has the following options: (1) a suitable out-of-stack filtration method may be used instead of in-stack filtration; or (2) a special in-stack arrangement, in which the sampling and velocity measurement sites are separate, may be used; for details concerning this approach, consult with the Administrator (see also Citation 10 in Section 7). Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particular sample run.


STACK WALL
TEMPERATURE SENSOR
SAMPLING NOZZLE
TYPE-S PITOT TUBE
IN-STACK FILTER-PROBE EXTENSION ASSEMBLY

$$\text{ESTIMATED BLOCKAGE (\%)} = \left[\frac{\text{SHADED AREA}}{\text{DUCT AREA}}\right] \times 100$$

Figure 17-2. Projected-area model of cross-section blockage (approximate average for a sample traverse) caused by an in-stack filter holder-probe extension assembly.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a probe extension length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 minutes (or some greater time interval if specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

If impingers are used to condense stack gas moisture, prepare them as follows: place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

If some means other than impingers is used to condense moisture, prepare the condenser (and, if appropriate, silica gel for condenser outlet) for use.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as not to allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed. Mark the probe extension with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Assemble the train as in Figure 17-1, using a very light coat of silicone grease on all ground glass joints and greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Place crushed ice around the impingers.

4.1.4 Leak Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, plug the inlet to the probe nozzle with a material that will be able to withstand the stack temperature. Insert the filter holder into the stack and wait approximately 5 minutes (or longer, if necessary) to allow the system to come to equilibrium with the temperature of the stack gas stream. Turn on the pump and draw a vacuum of at least 380 mm Hg (15 in. Hg); note that a lower vacuum may be used, provided that it is not exceeded during the test. Determine the leakage rate. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m^3/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until the desired vacuum is reached. Do not reverse direction of by-pass valve. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak-check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe nozzle and immediately turn off the vacuum pump. This prevents water from being forced backward and keeps silica gel from being entrained backward.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-Test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain a sampling rate such that sampling is within 10 percent of true isokinetic, unless otherwise specified by the Administrator.

For each run, record the data required on the example data sheet shown in Figure 17-3. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted. Take other readings required by Figure 17-3 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

PLANT ____________
LOCATION ____________
OPERATOR ____________
DATE ____________
RUN NO. ____________
SAMPLE BOX NO. ____________
METER BOX NO. ____________
METER ΔH@ ____________
C FACTOR ____________
PITOT TUBE COEFFICIENT, Cp ____________

SCHEMATIC OF STACK CROSS SECTION

BAROMETRIC PRESSURE ____________
ASSUMED MOISTURE, % ____________
PROBE EXTENSION LENGTH, m(ft.) ____________
NOZZLE IDENTIFICATION NO. ____________
AVERAGE CALIBRATED NOZZLE DIAMETER, cm(in.) ____________
FILTER NO. ____________
LEAK RATE, m^3/min,(cfm) ____________
STATIC PRESSURE, mm Hg (in. Hg) ____________

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_S), °C (°F)	VELOCITY HEAD (ΔP_S), mm H_2O (in. H_2O)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER, mm H_2O (in. H_2O)	GAS SAMPLE VOLUME, m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET, °C (°F)	OUTLET, °C (°F)	
TOTAL							Avg	Avg	
AVERAGE							Avg		

Figure 17-3. Particulate field data.

Clean the portholes prior to the test run to minimize the chance of sampling the deposited material. To begin sampling, remove the nozzle cap and verify that the pitot tube and probe extension are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment to the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85±0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29±4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomographs unless appropriate steps (see Citation 7 in Section 7) are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe extension assembly into the stack to prevent water from being forced backward. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe extension through the portholes, to minimize chance of extracting deposited material.

During the test run, take appropriate steps (e.g., adding crushed ice to the impinger ice bath) to maintain a temperature of less than 20° C (68° F) at the condenser outlet; this will prevent excessive moisture losses. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter holder assembly be used rather than attempting to change the filter itself. Before a new filter holder is installed, conduct a leak check, as outlined in Section 4.1.4.2. The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator. Note that when two or more trains are used, a separate analysis of the collected particulate from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case the particulate catches from the individual trains may be combined and a single analysis performed.

At the end of the sample run, turn off the pump, remove the probe extension assembly from the stack, and record the final dry gas meter reading. Perform a leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Section 3.1 of Method 2; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Section 6.11) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe extension assembly is removed from the stack at the end of the sampling period. Allow the assembly to cool.

When the assembly can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, forcing condenser water backward.

Before moving the sample train to the cleanup site, disconnect the filter holder-probe nozzle assembly from the probe extension; cap the open inlet of the probe extension. Be careful not to lose any condensate, if present. Remove the umbilical cord from the condenser outlet and cap the outlet. If a flexible line is used between the first impinger (or condenser) and the probe extension, disconnect the line at the probe extension and let any condensed water or liquid drain into the impingers or condenser. Disconnect the probe extension from the condenser; cap the probe extension outlet. After wiping off the silicone grease, cap off the condenser inlet. Ground glass stoppers, plastic caps, or serum caps (whichever are appropriate) may be used to close these openings.

Transfer both the filter holder-probe nozzle assembly and the condenser to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe nozzle or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, fitting, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone.

Brush and rinse with acetone the inside parts of the fitting in a similar way until no visible particles remain. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Rinse the brush with acetone and quantitatively collect these washings in the sample container. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints are wiped clean of silicone grease (if applicable), clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make final rinse of the brush and filter holder. After all acetone washings and particulate matter are collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents.

Container No. 3. If silica gel is used in the condenser system for mositure content determination, note the color of the gel to determine if it has been completely spent; make a notation of its condition. Transfer the silica gel back to its original container and seal. A funnel may make it easier to pour the silica gel without spilling, and a rubber policeman may be used as an aid in removing the silica gel. It is not necessary to remove the small amount of dust particles that may adhere to the walls and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for Container No. 3 under "Analysis."

Condenser Water. Treat the condenser or impinger water as follows: make a notation of any color or film in the liquid catch. Measure the liquid volume to within ±1 ml by using a graduated cylinder or, if a balance is available, determine the liquid weight to within ±0.5 g. Record the total volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas. Discard the liquid after measuring and recording the volume or weight.

4.3 Analysis. Record the data required on the example sheet shown in Figure 17-4. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at the average stack temperature or

105° C (220° F), whichever is less, for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at the average stack temperature or 105° C (220° F), whichever is less, for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Plant ____________________

Date ____________________

Run No. ____________________

Filter No. ____________________

Amount liquid lost during transport ____________________

Acetone blank volume, ml ____________________

Acetone wash volume, ml ____________________

Acetone black concentration, mg/mg (equation 17-4) ____________________

Acetone wash blank, mg (equation 17-5) ____________________

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL			
		Less acetone blank	
		Weight of particulate matter	

	VOLUME OF LIQUID WATER COLLECTED	
	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g
FINAL		
INITIAL		
LIQUID COLLECTED		
TOTAL VOLUME COLLECTED		g* ml

* CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER (1g/ml).

$$\frac{\text{INCREASE, g}}{1\ \text{g/ml}} = \text{VOLUME WATER, ml}$$

Figure 17-4. Analytical data.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. This step may be conducted in the field. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

NOTE.—At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. *Calibration.* Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. If the pitot tube is placed in an interference-free arrangement with respect to the other probe assembly components, its baseline (isolated tube) coefficient shall be determined as outlined in Section 4 of Method 2. If the probe assembly is not interference-free, the pitot tube assembly coefficient shall be determined by calibration, using methods subject to the approval of the Administrator.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD-0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values.

Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m^3/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m^3/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD-0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

NOTE.—If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.5 Leak Check of Metering System Shown in Figure 17-1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 17-5). Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

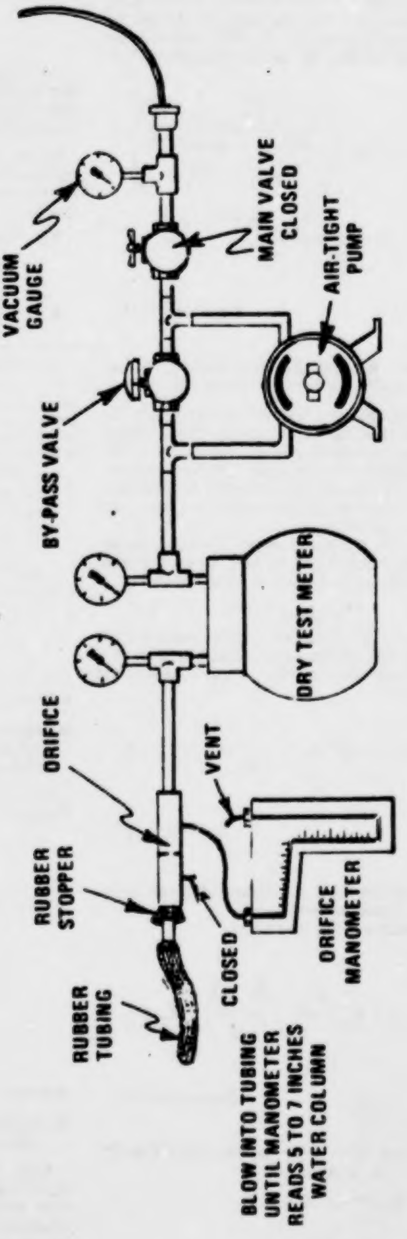

VACUUM GAUGE
MAIN VALVE CLOSED
AIR-TIGHT PUMP
BY-PASS VALVE
DRY TEST METER
ORIFICE
VENT
RUBBER STOPPER
RUBBER TUBING
CLOSED
ORIFICE MANOMETER
BLOW INTO TUBING UNTIL MANOMETER READS 5 TO 7 INCHES WATER COLUMN

Figure 17-5. Leak check of meter box.

5.6 Barometer. Calibrate against a mercury barometer.

6. *Calculations.* Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

6.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m^2 (ft^2).
B_{ws} = Water vapor in the gas stream, proportion by volume.
C_a = Acetone blank residue concentration, mg/g.
c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).
I = Percent of isokinetic sampling
L_a = Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.
L_i = Individual leakage rate observed during the leak check conducted prior to the "i^{th}" component change ($i = 1, 2, 3 \ldots n$), m^3/min (cfm).
L_p = Leakage rate observed during the post-test leak check, m^3/min (cfm).
m_n = Total amount of particulate matter collected, mg.
M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).
m_a = Mass of residue of acetone after evaporation, mg.
P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R = Ideal gas constant, 0.06236 mm Hg-m^3/°K-g-mole (21.85 in. Hg-ft^3/°R-lb-mole).
T_m = Absolute average dry gas meter temperature (see Figure 17-3), °K (°R).
T_s = Absolute average stack gas temperature (see Figure 17-3), °K (°R).
T_{std} = Standard absolute temperature, 293°K (528°R).
V_a = Volume of acetone blank, ml.
V_{aw} = Volume of acetone used in wash, ml.
V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 17-4), ml.
V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).
v_s = Stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 17, m/sec (ft/sec).
W_a = Weight of residue in acetone wash, mg.
Y = Dry gas meter calibration coefficient.
ΔH = Average pressure differential across the orifice meter (see Figure 17-3), mm H_2O (in. H_2O).
ρ_a = Density of acetone, mg/ml (see label on bottle).
ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).
θ = Total sampling time, min.
θ_1 = Sampling time interval, from the beginning of a run until the first component change, min.
θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.
θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.
13.6 = Specific gravity of mercury.
60 = Sec/min.
100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 17-3).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 17-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right]$$

$$= K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 17-1

where:

K_1 = 0.3858 °K/mm Hg for metric units; 17.64 °R/in. Hg for English units.

NOTE.—Equation 17-1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 17-1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 17-1 with the expression:

$$[V_m - (L_p - L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 17-1 by the expression:

$$[V_m - (L_1 - L_a)\theta_1 - \sum_{i=2}^{n}(L_i - L_a)\theta_i$$

$$- (L_p - L_a)\theta_p]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

$$V_{w(std)} = V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2 V_{lc}$$

Equation 17-2

where:

K_2 = 0.001333 m^3/ml for metric units; 0.04707 ft^3/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}}$$

Equation 17-3

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a}$$

Equation 17-4

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a$$

Equation 17-5

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 17-4).

NOTE.—Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001 \text{ g/mg})(m_n/V_{m(std)})$$

Equation 17-6

6.10 Conversion Factors:

From	To	Multiply by
scf	m^3	0.02832
g/ft^3	gr/ft^3	15.43
g/ft^3	lb/ft^3	2.205×10^{-3}
g/ft^3	g/m^3	35.31

6.11 Isokinetic Variation.

6.11.1 Calculation from Raw Data.

$$I = \frac{100\, T_s\, [K_3 V_{lc} + (V_m Y/T_m)(P_{bar} + \Delta H/13.6)]}{60\, \theta v_s P_s A_n}$$

Equation 17-7

where:

K_3 = 0.003454 mm Hg-m^3/ml-°K for metric units; 0.002669 in. Hg-ft^3/ml-°R for English units.

6.11.2 Calculation from Intermediate Values.

$$I = \frac{T_s V_{m(std)} P_{std}\, 100}{T_{std} v_s \theta A_n P_s\, 60\, (1 - B_{ws})}$$

$$= K_4 \frac{T_s V_{m(std)}}{P_s v_s A_n \theta (1 - B_{ws})}$$

Equation 17-8

where:

K_4 = 4.320 for metric units; 0.09450 for English units.

6.12 Acceptable Results. If 90 percent 010110 percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 in Section 7 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography.*

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9. Annual Book of ASTM Standards. Part 26. Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 617-622.

10. Vollaro, R. F., Recommended Procedure for Sample Traverses in Ducts Smaller than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N.C. November, 1976.

[FR Doc. 78-4795 Filed 2-22-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 37

THURSDAY, FEBRUARY 23, 1978

83

Title 40—Protection of Environment

[FRL 848-2]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Revision of Authority Citations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action amends the authority citiations for Standards of Performance for New Stationary Sources and National Emission Stantards for Hazardous Pollutants. The amendment adopts the redesignation of classification numbers as changed in the 1977 amendments to the Clean Air Act. As amended, the Act formerly classified to 42 U.S.C. 1857 et seq. has been transferred and is now classified to 42 U.S.C. 7401 et seq.

EFFECTIVE DATE: March 3, 1978.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711 telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: This action is being taken in accordance with the requirements of 1 CFR 21.43 and is authorized under section 301(a) of the Clean Air Act, as amended, 42 U.S.C. 7601(a). Because the amendments are clerical in nature and affect no substantive rights or requirements, the Administrator finds it unnecessary to propose and invite public comment.

Dated: February 24, 1978.

DOUGLAS M. COSTLE,
Administrator.

Parts 60 and 61 of Chapter I, Title 40 of the Code of Federal Regulations are revised as follows:

1. The authority citation following the table of sections in Part 60 is revised to read as follows:

AUTHORITY: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), unless otherwise noted.

§§ 60.10 and 60.24 [Amended]

2. Following §§ 60.10 and 60.24(g) the following authority citation is added:

(Sec. 116 of the Clean Air Act as amended (42 U.S.C. 7416)).

§§ 60.7, 60.8, 60.9, 60.11, 60.13, 60.45, 60.46, 60.53, 60.54, 60.63, 60.64, 60.73, 60.74, 60.84, 60.85, 60.93, 60.105, 60.106, 60.113, 60.123, 60.133, 60.144, 60.153, 60.154, 60.165, 60.166, 60.175, 60.176, 60.185, 60.186, 60.194, 60.195, 60.203, 60.204, 60.213, 60.214, 60.223, 60.224, 60.233, 60.234, 60.243, 60.244, 60.253, 60.254, 60.264, 60.265, 60.266, 60.273, 60.274, 60.275, and Appendices A, B, C, and D [Amended]

3. The following authority citation is added to the above sections and appendices:

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).

FEDERAL REGISTER, VOL. 43, NO. 43

FRIDAY, MARCH 3, 1978

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Lignite-Fired Steam Generators

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This final rule establishes standards of performance for new or modified lignite-fired steam generators with heat input rates greater than 73 megawatts (250 million Btu per hour) and limits emissions of nitrogen oxides to 260 ng/J of heat input except that 340 ng/J of heat input is allowed from cyclone-fired units which are fired with lignite mined in North Dakota, South Dakota, or Montana. Steam generators contribute significantly to air pollution, and the intended effect of this final rule is to require new steam generators which burn lignite to use the best control system for reducing emissions of nitrogen oxides.

EFFECTIVE DATE: March 7, 1978.

ADDRESSES: The "Standards Support and Environmental Impact Statement (SSEIS), Volume 2: Promulgated Standards of Performance for Lignite-Fired Steam Generators" (EPA-450/2-76-030b) may be obtained by writing the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711. Volume 1 of the SSEIS, "Proposed Standards of Performance for Lignite-Fired Steam Generators" (EPA-450/2-76-030a), is also available at the same address. Please specify both the title and EPA number of the document desired. These documents and all public comments may be inspected at the Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On December 23, 1971 (36 FR 24877), EPA established under Subpart D of 40 CFR Part 60 standards of performance for new steam generators with heat input rates greater than 73 megawatts (250 million Btu per hour). Steam generators which burn lignitie were exempted from the emission standards for nitrogen oxides (NO_x) because too little operating experience was available to adequately characterize NO_x emissions. (Lignite-fired steam generators were not exempted from the standards for sulfur oxides and particulate matter, however.) Since 1971, EPA has gathered additional information on lignite-fired facilities, and on December 22, 1976 (41 FR 55791), the Agency proposed to amend Subpart D by establishing a standard of performance of 260 nanograms per joule (ng/J) of heat input (0.6 pound per million Btu) for NO_x emissions from new lignite-fired steam generators. Supporting information for the proposed standard was published in Volume 1 of the SSEIS for lignite-fired steam generators. After reviewing issues raised during the public comment period which followed the proposal, EPA decided to promulgate standards which will permit the limited use of cyclone-fired facilities to burn lignite mined in North Dakota, South Dakota, and Montana (which causes severe fouling and slagging in pulverized-fired units). Supporting information for these final standards of performance appears in Volume 2 of the SSEIS.

FINAL STANDARDS

NO_x emissions from lignite-fired steam generators are limited to 260 ng/J of heat in put (0.6 lb/10^6 Btu) except that 340 ng/J (0.8 lb/10^6 Btu) is allowed from cyclone-fired steam generators burning lignite mined in North Dakota, South Dakota, and Montana. Both standards apply only to boilers which burn lignite, with heat input rates greater than 73 megawatts (250 million Btu per hour), and for which construction or modification began after December 21, 1976.

RATIONALE FOR FINAL STANDARDS

The NO_x standard originally proposed by EPA, 260 ng/J, may have prevented the use of cyclone-fired boilers, since it has not been demonstrated that emisisons from these units can be consistently controlled to levels below 260 ng/J. During the public comment period, several commenters argued that the utilization of cyclone-fired boilers is necessary to overcome the serious fouling and slagging problems which develop whenever the sodium content of the lignite burned exceeds about 5 percent, by weight. These high sodium content reserves are believed to be widespread, especially in North Dakota, and the utilities claim that their low sodium content reserves are being rapidly depleted. The commenters said that cyclones have inherently lower fouling and slagging rates than other large boiler designs because much less ash is carried through the boiler convective passes. In addition, they contended that in the Dakotas there has actually been very little operating experience with pulverized-fired boilers, the alternative to large cyclones, and it is doubtful that these units can burn high sodium lignite without experiencing severe problems. Thus, the commenters concluded that the proposed standard might restrict the use of valuable resources of high sodium lignite fuel by prohibiting the utilization of cyclone-fired boilers. The commenters also argued that the proposed standard would place an economic burden on the electirc power utilities which burn lignite by limiting competitve bidding for new boilers.

EPA agrees that at present there is too little operating experience with pulverized- or cyclone-fired boilers to be able to predict their reliability when burning high sodium lignite. Furthermore, the Agency does not want to establish a standard which might inhibit future efforts to find a successful way to burn this troublesome fuel. Consequently, EPA has established a separate nitrogen oxides emission standard of 340 ng/J (0.8 lb/10^6 Btu) for new cyclone-fired boilers which burn North Dakota, South Dakota, or Montana lignite. This standard will permit the limited utilization of cyclone-fired boilers and assure the continued use of our country's abundant resources of lignite. Lignite mined in Texas, the only other known major lignite formation, generally has low sodium content and has been successfully burned in pulverized-fired units for years. The standard is supported by emission test data and other information contained in Volume I of the SSEIS. Nitrogen oxides emissions from pulverized-fired boilers will be limited to 260 ng/J (0.6 lb/10^6 Btu), as originally proposed.

Cyclone-fired boilers could account for 10 to 20 percent of all new lignite-fired steam generators, based on EPA estimates of lignite consumption for the year 1980. EPA estimates that NO_x emissions from new cyclone-fired boilers may be reduced by as much as 20 percent as a result of the standard. The combined effect of both standards will be to reduce total NO_x emissions from all new boilers which burn lignite by about 25 percent.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173 of the Act requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source as defined in section 171(3), unless the owner or operator demonstrates that the source cannot achieve such an emission rate. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term "best available control technology" (BACT) means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), costs must be accorded far less weight in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

ENVIRONMENTAL AND ECONOMIC IMPACTS

The impact of the NO_x emission standards will be most significant in North Dakota and Texas where most new lignite-fired boilers will be located. Although ambient NO_x levels in these areas are now low, emission regulations are important because: (1) The standards will maintain low ambient NO_x concentrations in areas where population and industrial growth is expected in the future; (2) the standards will reduce the potential for development of rural smog which can form in regions having initially low ambient NO_x concentrations; and (3) the standards will reduce long distance transport of NO_x to areas having air pollution problems. In addition, since nationwide levels of NO_x are expected to rise in the future despite NO_x control regulations, the NO_x emission standards for lignite-fired boilers will help to alleviate this problem.

The standards will cause total NO_x emissions from all new lignite-fired steam generators to be reduced by about 25 percent. By comparison, NO_x emissions would have been reduced by about 29 percent if the use of cyclones had been restricted by the standard originally proposed. Thus, the continued use of cyclone-fired boilers will have only a minor adverse impact on air quality.

The NO_x emission standards will have no impact on water pollution, solid waste disposal, sulfur dioxide and particulate emissions, or energy consumption at new lignite-fired steam generators. In addition, the standards will not prohibit the use of any lignite reserves or adversely affect any other natural resources. Additional information about the environmental impact of the standards appears in Volumes 1 and 2 of the SSEIS.

The NO_x emission standards will cause capital costs for new lignite-fired plants to increase by, at most, only 0.5 percent and operating costs will rise even less. Therefore, capital and operating expenses will rise only nominally. Since the price consumers pay for electric power is generally proportional to the electric utility's operating costs, consumer power price increases will be negligible. The boiler manufacturers will experience no significant market disadvantages because the standards effectively permit the sale of all boiler designs and provide no sales advantages for any manufacturer. The small increases in capital costs resulting from the standards will not affect the boiler industry's overall sales. More information about the economic impact of the standards can be found in Volumes 1 and 2 of the SSEIS.

PUBLIC COMMENTS

Seventeen comment letters were received during the public comment period. Many of the comments were critical of the information EPA used to support restriction of the cyclone-fired boiler. In particular, these arguments were made: (1) None of the pulverized-fired boilers which EPA tested operate reliably when burning lignite with a sodium content above about 5 percent; (2) the front-wall-fired plant cited by EPA has never burned lignite with an 8 percent sodium content for an extended period of time, as EPA has reported. Also, the plant's capacity factor has averaged about 72 percent, not 86 percent as stated by EPA; (3) although it is true that a North Dakota electric utility has recently agreed to purchase two tangentially-fired boilers, these units are guaranteed to burn lignite containing no more than 4.8 percent sodium. Also, the decision to purchase these boilers may have been influenced by the utility's concern that EPA might prohibit the use of cyclones; (4) recent experiments by the Energy Research and Development Administration have demonstrated that cyclone-fired boilers have significantly lower ash deposition rates than pulverized-fired boilers. This confirms arguments that cyclones have much lower fouling and slagging potentials when burning high sodium content lignite.

EPA agrees that there has not been enough successful operating experience with pulverized-fired boilers which burn high sodium content lignite to justify eliminating cyclones from the market. Consequently, the Agency has decided to establish a separate NO$_x$ emission standard for cyclones burning Dakota lignite which permits their use.

Another issue raised during the comment period concerned the potentially high NO$_x$ emissions which could occur when Texas lignite with a high nitrogen content is burned. It was argued that these emissions could exceed the standard even if the best system of emission reduction were employed. In support of this contention, a commenter submitted data which indicate that the fuel-nitrogen content of Texas lignites ranges well above expected values. EPA has determined, however, that these data were accumulated around the turn of the century and are inconsistent with present-day values. Information from the Bureau of Economic Geology at the University of Texas and the Texas Railroad Commission indicates that Texas lignite nitrogen contents are typically low and should not cause NO$_x$ emissions from a well controlled plant to exceed the standard.

These and all other comments are discussed in detail in Volume 2, Chapter 2 of the SSEIS.

The effective date of this regulation is (date of publication), because section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: March 2, 1978.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended by revising Subparts A and D as follows:

Subpart A—General Provisions

1. Section 60.2 is amended by substituting the International System of Units (SI) in paragraph (1) as follows:

§ 60.2 Definitions.

* * * * *

(1) "Standard conditions" means a temperature of 293 K (68° F) and a pressure of 101.3 kilopascals (29.92 in Hg).

* * * * *

Subpart D—Standards of Performance for Fossil Fuel-Fired Steam Generators

2. Section 60.40 is amended by revising paragraph (c) and by adding paragraph (d) as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§ 60.44(a)(4), (a)(5), (b), and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

3. Section 60.41 is amended by adding paragraph (f) as follows:

§ 60.41 Definitions.

* * * * *

(f) "Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing Material. Designation D 388-66.

4. Section 60.44 is amended by adding paragraphs (a)(4) and (a)(5), by revising paragraph (b), and by adding paragraphs (c) and (d) as follows:

§ 60.44 Standard for nitrogen oxides.

(a) * * *

(4) 260 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c) and (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w(260) + x(86) + y(130) + z(300)}{w + x + y + z}$$

where:

PS_{NO_x} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for nitrogen oxides does not apply.

(d) Cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(Sections 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, and 7601).)

5. Section 60.45 is amended by adding paragraph (f)(4)(vi) as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(f) * * *

(4) * * *

(vi) For lignite coal as classified according to A.S.T.M. D 388-66, $F = 2.659 \times 10^{-7}$ dscm/J (9900 dscf/million Btu) and $F_c = 0.516 \times 10^{-7}$ scm CO$_2$/J (1920 scf CO$_2$/million Btu).

(Sections 111, 114, and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7414, and 7601).)

[FR Doc. 78-5975 Filed 3-6-78; 8:45 am]

85

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 835-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Lime Manufacturing Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule establishes standards of performance which limit emissions of particulate matter from new, modified, and reconstructed lime manufacturing plants. The standards implement the Clean Air Act and are based on the Administrator's determination that lime manufacturing plant emissions contribute significantly to air pollution. The intended effect of setting these standards is to require, new, modified, and reconstructed lime manufacturing plants to use the best demonstrated system of continuous emission reduction.

EFFECTIVE DATE: March 7, 1978.

ADDRESSES: A support document entitled, "Standard Support and Environmental Impact Statement, Volume II: Promulgated Standards of Performance for Lime Manufacturing Plants" (EPA-450/2-77-007b), October 1977, has been prepared and is available. This document includes summary economic and environmental impact statements as well as EPA's responses to the comments on the proposed standards. Also available is the supporting volume for the proposed standards entitled, "Standard Support and Environmental Impact Statement, Volume I: Proposed Standards of Performance for Lime Manufacturing Plants" (EPA-450/2-77-007a), April 1977. Copies of these documents can be ordered by addressing a request to the EPA Library (MD-35), Research Triangle Park, N.C. 27711. The title and number for each or both of the documents should be specified when ordering. These documents as well as copies of the comment letters responding to the proposed rulemaking published in the FEDERAL REGISTER on May 3, 1977 (42 FR 22506) are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: There are two minor changes in the standards from those proposed on May 3, 1977. The first of these is the specific exclusion of lime production units at kraft pulp mills [§60.340(b)]. Emission standards for kraft pulp mills were proposed in the FEDERAL REGISTER on September 24, 1976, which cover emissions from the lime production units at these mills.

The second change is the addition of §60.344(c) (Test methods and procedures). The addition recommends a testing technique which would more accurately test exhaust gases from hydrators in those cases where high moisture content is a problem.

During the 60-day comment period following publication of the proposed emission standards in the FEDERAL REGISTER on May 3, 1977, 23 comment letters were received, 10 from industry, 7 from State or local pollution control agencies, and 6 from other government agencies. In addition, on June 16, 1977, a public meeting was held at the EPA facility at Research Triangle Park, N.C., that provided an opportunity for oral presentations and comments on the standards. None of the comments warranted a change of the emission standards nor did any comments justify any significant changes in the standards support document.

Major comments focused on three areas: (1) criticism of the testing procedures and the supporting emission data, (2) the opacity standard, and (3) the requirement for continuous monitoring. These and other comments are summarized and addressed in Volume II of the standards support document.

The most significant of the three areas of comments was the questioning of the testing procedures and the data base. More specifically, it was asserted that when data were gathered upon which to base the standard, standard testing procedures were not followed in every case, which consequently biased the data. A careful review of the procedures and the resulting data revealed that, although there were minor miscalculations, the errors did not affect the emission standards that were set.

The opacity standard (10 percent), was questioned because it was thought to be too stringent and in a range where observer error would result in unfair violation decisions. A review of the opacity data indicated that of the 1,056 six-minute averages of opacity, less than one percent exceeded the visible emission level of 10 percent, thus EPA considers the 10 percent opacity standard reasonable. As for observer error, as indicated in the introduction to Reference Method 9 (Part 60, Appendix A), the accuracy of the method and any potential error must be taken into account when determining possible violations of the standards.

Some commenters questioned the requirement for continuous monitoring of multiple stack baghouses, believing it to be unnecessary and excessively expensive to place a monitor on each stack. In establishing the continuous monitoring requirement, it was not the intention of EPA that emission monitors be installed at each stack at a multiple stack baghouse. The proposed regulation has been revised to reflect this intent. It is believed that in most cases one monitor, or two in certain situations, can be installed to simultaneously monitor emissions from several stacks. With such a monitoring system, the plant must demonstrate that representative emissions are monitored on a continuous basis.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173 of the Act requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology for all pollutants regulated under the Act. The term "best available control technology" (BACT), as defined in section 169(3), means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), statutorily, costs do not play such a role in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

MISCELLANEOUS: The effective date of this regulation is March 7, 1978. Section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions of them become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (May 3, 1977).

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: March 1, 1978.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I of Title 40 of the Code of Regulations is amended as follows:

1. By adding subpart HH as follows:

Subpart HH—Standards of Performance for Lime Manufacturing Plants

Sec.
60.340 Applicability and designation of affected facility.
60.341 Definitions.
60.342 Standard for particulate matter.
60.343 Monitoring of emissions and operations.
60.344 Test methods and procedures.

AUTHORITY: Sec. 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601), and additional authority as noted below.

§ 60.340 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities used in the manufacture of lime: rotary lime kilns and lime hydrators.

(b) The provisions of this subpart are not applicable to facilities used in the manufacture of lime at kraft pulp mills.

(c) Any facility under paragraph (a) of this section that commences construction or modification after May 3, 1977, is subject to the requirements of this part.

§ 60.341 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in subpart A of this part.

(a) "Lime manufacturing plant" includes any plant which produces a lime product from limestone by calcination. Hydration of the lime product is also considered to be part of the source.

(b) "Lime product" means the product of the calcination process including, but not limited to, calcitic lime, dolomitic lime, and dead-burned dolomite.

(c) "Rotary lime kiln" means a unit with an inclined rotating drum which is used to produce a lime product from limestone by calcination.

(d) "Lime hydrator" means a unit used to produce hydrated lime product.

§ 60.342 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any rotary lime kiln any gases which:

(i) Contain particulate matter in excess of 0.15 kilogram per megagram of limestone feed (0.30 lb/ton).

(ii) Exhibit 10 percent opacity or greater.

(2) From any lime hydrator any gases which contain particulate matter in excess of 0.075 kilogram per megagram of lime feed (0.15 lb/ton).

§ 60.343 Monitoring of emissions and operations.

(a) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate a continuous monitoring system, except as provided in paragraph (b) of this section, to monitor and record the opacity of a representative portion of the gases discharged into the atmosphere from any rotary lime kiln. The span of this system shall be set at 40 percent opacity.

(b) The owner or operator of any rotary lime kiln using a wet scrubbing emission control device subject to the provisions of this subpart shall not be required to monitor the opacity of the gases discharged as required in paragraph (a) of this section, but shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be accurate within ±250 pascals (one inch of water).

(2) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control device. The monitoring device must be accurate within ±5 percent of design scrubbing liquid supply pressure.

(c) The owner or operator of any lime hydrator using a wet scrubbing emission control device subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measuring of the scrubbing liquid flow rate. The monitoring device must be accurate within ±5 percent of design scrubbing liquid flow rate.

(2) A monitoring device for the continuous measurement of the electric current, in amperes, used by the scrubber. The monitoring device must be accurate within ±10 percent over its normal operating range.

(d) For the purpose of conducting a performance test under § 60.8, the owner or operator of any lime manufacturing plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device for measuring the mass rate of limestone feed to any affected rotary lime kiln and the mass rate of lime feed to any affected lime hydrator. The measuring device used must be accurate to within ±5 percent of the mass rate over its operating range.

(e) For the purpose of reports required under §60.7(c), periods of excess emissions that shall be reported are defined as all six-minute periods during which the average opacity of the plume from any lime kiln subject to paragraph (a) of this subpart is 10 percent or greater.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 7414).)

§60.344 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under §60.8(b), shall be used to determine compliance with §60.322(a) as follows:

(1) Method 5 for the measurement of particulate matter,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate,

(4) Method 3 for gas analysis,

(5) Method 4 for stack gas moisture, and

(6) Method 9 for visible emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.85 std m³/h, dry basis (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Because of the high moisture content (40 to 85 percent by volume) of the exhaust gases from hydrators, the Method 5 sample train may be modified to include a calibrated orifice immediately following the sample nozzle when testing lime hydrators. In this configuration, the sampling rate necessary for maintaining isokinetic conditions can be directly related to exhaust gas velocity without a correction for moisture content. Extra care should be exercised when cleaning the sample train with the orifice in this position following the test runs.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 7414).)

[FR Doc. 78-5974 Filed 3-6-78; 8:45 am]

86

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 836-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Petroleum Refinery Claus Sulfur Recovery Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule establishes standards of performance which will limit emissions of sulfur dioxide (SO_2) and reduced sulfur compounds from new, modified, and reconstructed petroleum refinery Claus sulfur recovery plants. The standards implement the Clean Air Act and are based on the Administrator's determination that emissions from petroleum refinery Claus sulfur recovery plants contribute significantly to air pollution. The intended effect of the standards is to require new, modified, and reconstructed petroleum refinery Claus sulfur recovery plants to use the best technological system of continuous emission reduction.

EFFECTIVE DATE: March 15, 1978.

ADDRESSES: Copies of the standard support documents are available on request from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711. The requestor should specify "Standards Support and Environmental Impact Statement, Volume I: Proposed Standards of Performance for Petroleum Refinery Sulfur Recovery Plants" (EPA-450/2-76-016a) and/or "Standards Support and Environmental Impact Statement, Volume II: Promulgated Standards of Performance for Petroleum Refinery Sulfur Recovery Plants" (EPA-450/2-76-016b). Comment letters responding to the proposed rules published in the FEDERAL REGISTER on October 4, 1976 (41 FR 43866), are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number 919-541-5271.

SUPPLEMENTARY INFORMATION:

SUMMARY

On October 4, 1976 (41 FR 43866), EPA proposed standards of performance for new petroleum refinery Claus sulfur recovery plants under section 111 of the Clean Air Act, as amended. The promulgated standards are essentially the same as those proposed, although an exemption for small petroleum refineries has been included in the promulgated standards. The standards are based on the use of tail gas scrubbing systems which have been determined to be the best technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality, health, and environmental impact and energy requirements. Compliance with these standards will increase the overall sulfur recovery efficiency of a typical refinery Claus sulfur recovery plant to about 99.9 percent, compared to a recovery efficiency of about 94 percent for an uncontrolled refinery Claus sulfur recovery plant, or a recovery efficiency of about 99 percent for a Claus sulfur recovery plant complying with typical State emission control regulations for these plants.

The promulgated standards will apply to: (1) any Claus sulfur recovery plant with a sulfur production capacity of more than 20 long tons per day (LTD) which is associated with a small petroleum refinery (i.e., a petroleum refinery having a crude oil processing capacity of 50,000 barrels per stream day (BSD) or less which is owned or controled by a refiner whose total combined crude oil processing capacity is 137,500 BSD or less) and (2) any size Claus sulfur recovery plant associated with a large petroleum refinery. Specifically, the standards limit the concentration of sulfur dioxide (SO_2) in the gases discharged into the atmosphere to 0.025 percent by volume at zero percent oxygen on a dry basis. Where the emission control system installed to comply with these standards discharges residual emissions of hydrogen sulfide (H_2S), carbonyl sulfide (COS), and carbon disulfide (CS_2), the standards limit the concentration of H_2S and the total concentration of H_2S, COS and CS_2 (calculated as SO_2) in the gases discharged into the atmosphere to 0.0010 percent and 0.030 percent by volume at zero percent oxygen on a dry basis, respectively.

Compliance with these standards will reduce nationwide sulfur dioxide emissions by some 55,000 tons per year by 1980. This reduction will be achieved without any significant adverse impact on other aspects of environmental quality, such as solid waste disposal, water pollution, or noise. This reduction in emissions will also be accompanied by a reduction in the growth of nationl energy consumption equivalent to about 90,000 barrels of fuel oil per year by 1980.

The economic impact of the promulgated standards is reasonable. They will result in an increase in the annual operating costs of the petroleum refining industry by some $16 million per year in 1980. An individual refiner who installs alternative II controls will need to increase his prices from 0.1 to 1 percent to maintain his profitability.

It should be noted that standards of performance for new sources established under section 111 of the Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reduction than those required by standards of performance for new sources. Section 173(2) of the Act requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source, unless the owner or operator demonstrates that the source cannot achieve such an emission rate. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to the best available control technology. The term "best available control technology" (BACT) means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), costs must be accorded far less weight in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

PUBLIC PARTICIPATION

Prior to proposal of the standards, interested parties were advised by public notice in the FEDERAL REGISTER of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the standards recommended for proposal. This meeting was open to the public and each person attending was given ample opportunity to comment on the standards recommended for proposal. The standards were proposed on October 4, 1976, and copies of the proposed standards and the Standards Support and Environmental Impact Statement (SSEIS) were distributed to members of the petroleum refining industry and several environmental groups at this time. The public comment period extended from October 4, 1976, to December 3, 1976.

Twenty-two comment letters were received on the proposed standards of performance. These comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the standards which were proposed.

MAJOR COMMENTS

Comments on the proposed standards were received from several oil industry representatives, State and local air pollution control agencies, a vendor of emission source testing equipment, and several Federal agencies. These comments covered four major areas: the costs of implementing the standards, the ability of emission control technology to meet the standards, the environmental impacts of the standards, and the energy impacts of the standards.

COSTS

The major comments concerning costs were that the costs of the emission control systems required to meet the standards were underestimated, that these costs were excessive; and that small sulfur recovery plants, or small petroleum refineries should be exempt from the standard.

The basic cost data used to develop the cost estimates were obtained from pretroleum refinery sources. No specific data or information was provided in the public comments, however, which would indicate that these costs are significantly in error.

In the preamble to the proposed standards, comments were specifically invited concerning the impact of the standards on the small refiner. After considering these comments, EPA has concluded that some relief from the standards is appropriate. The major factor involved in this decision was a consideration of the cost effectiveness of the standards on large and small refiners. The incremental cost per incremental unit of sulfur emissions that must be controlled to meet the standards is substantially greater for the small refiner than for the large refiner. Furthermore, the impact of these costs on the small refiner is more severe than the impact on the large refiner, because the small refiner cannot readily pass on the cost of emission control equipment. Consequently, as discussed in volume II of the Standards Support and Environmental Impact Statement (SSEIS), the promulgated standards include a lower size cutoff for small petroleum refineries and Claus sulfur recovery plants. Claus sulfur recovery plants with a sulfur production capacity of 20 long tons per day or less associated with a petroleum refinery with a crude oil processing capacity of 50,000 BSD or less, which is owned or controlled by a refiner whose total combined crude oil processing capacity is 137,500 BSD or less, are exempt from the standards. This definition of a small petroleum refinery is consistent with that included in section 211 of the Clean Air Act, as amended.

EMISSION CONTROL TECHNOLOGY

A major concern of many commenters was the limited amount of source test data used in support of the numerical emission limits included in the standards and the fact that some of these data were collected at refineries where the emission control system was operating below design capacity. Also, some commenters questioned the ability of the alternative II emission control systems to continuously operate at a 99.9 percent control efficiency because of the adverse impact of Claus sulfur recovery plant fluctuations and CO_2-rich waste gas streams.

In arriving at the numerical emissions limits included in the standards, source test data collected by a local agency at times when the emission control systems were operating at normal capacities, information from vendors of emission control equipment, published literature on emission control technology, and contractor reports on the performance of emission control technology were considered, in addition to the data collected during EPA's source tests. Based on the information and data from these sources and the lack of any new information and data submitted by the commenters, no change in the emission limits of the standards is warranted. Furthermore, the numerical emission limits in the standards contain an adequate safety margin to allow for increased emissions due to Clause sulfur recovery plant fluctuations.

With repect to the potential adverse impact of high CO_2 gas streams, this is not likely to impair the overall emission control system efficiency since high CO_2 gas streams are seldom found in the gases treated in refinery Claus sulfur recovery plants.

ENVIRONMENTAL IMPACT

Several commenters felt that the assessment of the environmental impact of the standards was, in some cases, biased and not always clear. One of these commenters suggested that a thorough environmental impact statement should be prepared to clarify the impacts of the standards.

Litigation involving standards of performance has established that preparation of a formal environmental impact statement under the National Environmental Policy Act is not necessary for actions under section 111 of the Clean Air Act. While a formal environmental impact statement is not prepared, the beneficial as well as the adverse impacts of standards of performance are considered. The promulgated standards will significantly reduce emissions of sulfur from petroleum refineries without resulting in any significant adverse environmental, energy, or economic impacts.

Other commenters felt that standards based on 99 percent control (alternative I) would be essentially as environmentally beneficial as standards based on 99.9 percent control and would be less costly to the public. This argument was based on the premise that most State regulations do not require control of Claus sulfur plant emissions at the 99 percent level as claimed in volume I of the SSEIS. Hence, standards based on alternative I would significantly reduce national sulfur emissions from refinery Claus sulfur recovery plants.

A review of State regulations for controlling emissions from refinery sulfur recovery plants has shown that the majority of the States with the largest petroleum refining capacities require 99 percent control of emissions from new and existing sulfur recovery plants. Since refinery sulfur recovery plant growth will likely occur in these States, the conclusion that standards based on 99 percent control would have little or no beneficial impact is essentially correct.

ENERGY IMPACT

Several commenters questioned the conclusion that compliance with standards based on alternative II could lead to an energy savings, compared to standards based on alternative I. A review of the information and data available confirms this conclusion. In any case, the important consideration is whether the energy impact of the standards is reasonable. No information was submitted which would indicate that the energy impact of the standards is unreasonable.

OTHER CONSIDERATIONS

At proposal comments were requested relative to EPA's decision to regulate reduced sulfur compound emissions, which are designated pollutants, without implementing section 111(d) of the Clean Air Act at this time. The one commenter who responded to this issue was in agreement with this decision.

As discussed in both the preamble to the proposed standards and volumes I and II of the SSEIS, petroleum refinery Claus sulfur recovery plants are sources of SO_2 emissions, not reduced sulfur compound emissions. One of the emission control technologies for reducing SO_2 emissions, however, first converts these emissions to reduced sulfur compounds and then controls these compounds. Consequently, this technology may discharge residual emissions of reduced sulfur compounds to the atmosphere.

Currently, there are about 30 refinery Claus sulfur recovery plants in the United States which have installed reduction emission control systems to reduce SO_2 emissions. A review of these plants indicates that these emission control systems are well designed and well maintained and operated. Emissions of reduced sulfur compounds are less than 0.050 percent (i.e., 500 ppm), which is only slightly higher than the numerical emission limit included in the promulgated standard. Thus, there is little to gain at this time by requiring States to develop regulations limiting emissions from these sources. Consequently, section 111(d) will not be implemented until resources permit, taking into consideration other requirements of the Clean Air Act, as amended, which EPA must implement.

Several commenters were concerned that Reference Method 15 might not be practical for use in a refinery environment. The basis for most of these objections was that the commenters thought this method was being proposed as a continuous monitoring method. However, Reference Method 15 was not proposed for use as a continuous monitoring method. Performance specifications for continuous monitors for reduced sulfur compounds have not been developed and therefore such monitors are not required to be installed until performance specifications for these monitors are proposed and promulgated under Appendix B of 40 CFR Part 60.

Reference Method 15 has been revised to allow greater flexibility in operating details and equipment choice. The user is now permitted to design his own sampling and analysis system as long as he preserves the operating principle of gas chromatography with flame photometric detection and meets the design and performance criteria.

MISCELLANEOUS

The effective date of this regulation is March 15, 1978. Section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions of them become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (October 4, 1976).

ECONOMIC IMPACT ASSESSMENT: An economic assessment has been prepared as required under section 317 of the Act. This also satisfies the requirements of Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: March 1, 1978.

DOUGLAS M. COSTLE,
Administrator.

1. Section 60.100 is amended as follows:

§ 60.100 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less associated with a small petroleum refinery. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator of fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this part.

(Secs. 111 and 301(a), Clean Air Act, as amended (42 U.S.C. 7411, 7601 (a)), and additional authority as noted below.)

2. Section 60.101 is amended as follows:

§ 60.101 Definitions.

* * * * *

(i) "Claus sulfur recovery plant" means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) "Oxidation control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) "Reduction control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) "Reduced sulfur compounds" mean hydrogen sulfide (H_2S), carbonyl sulfide (COS) and carbon disulfide (CS_2).

(m) "Small petroleum refinery" means a petroleum refinery which has a crude oil processing capacity of 50,000 barrels per stream day or less, and which is owned or controlled by a refinery with a total combined crude oil processing capacity of 137,500 barrels per stream day or less.

3. Section 60.102 is amended by revising paragraph (a) introductory text and paragraph (b) as follows:

§ 60.102 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) * * *

(2) * * *

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or sold fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43.0 g/MJ (0.10 lb/million Btu) of heat input attributable to such liquid or solid fossil fuel.

4. Section 60.104 is amended as follows:

§ 60.104 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas which contains hydrogen sulfide in excess of 230 mg/dscm (0.10 gr/dscf), except that the gases resulting from the combustion of fuel gas may be treated to control sulfur dioxide emissions provided the owner or operator demonstrates to the satisfaction of the Administrator that this is as effective in preventing sulfur dioxide emissions to the atmosphere as restricting the H_2 concentration in the fuel gas to 230 mg/dscm or less. The combustion in a flare of process upset gas, or fuel gas which is released to the flare as a result of relief valve leakage, is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) 0.025 percent by volume of sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by an oxidation control system, or a reduction control system followed by incineration, or

(ii) 0.030 percent by volume of reduced sulfur compounds and 0.0010 percent by volume of hydrogen sulfide calculated as sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by a reduction control system not followed by incineration.

(b) [Reserved]

5. Section 60.105 is amended as follows:

§ 60.105 Emission monitoring.

(a) * * *

(2) An instrument for continuously monitoring and recording the concentration of carbon monoxide in gases discharged into the atmosphere from fluid catalytic cracking unit catalyst regenerators. The span of this continuous monitoring system shall be 1,000 ppm.

(3) * * *

(4) An instrument for continuously monitoring and recording concentrations of hydrogen sulfide in fuel gases burned in any fuel gas combustion device, if compliance with § 60.104(a)(1) is achieved by removing H_2S from the fuel gas before it is burned; fuel gas combustion devices having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas burned. The span of this continuous monitoring system shall be 300 ppm.

(5) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases discharged into the atmosphere from any Claus sulfur recovery plant if compliance with § 60.104(a)(2) is achieved through the use of an oxidation control system or a reduction control system followed by incineration. The span of this continuous monitoring system shall be sent at 500 ppm.

(6) An instrument(s) for continuously monitoring and recording the concentration of H_2S and reduced sulfur compounds in the gases discharged into the atmosphere from any Claus sulfur recovery plant if compliance with § 60.104(a)(2) is achieved through the use of a reduction control system not followed by incineration. The span(s) of this continuous monitoring system(s) shall be set at 20 ppm for monitoring and recording the concentration of H_2S and 600 ppm for monitoring and recording the concentration of reduced sulfur compounds.

* * * * *

(e) * * *

(1) * * *

(2) Carbon monoxide. All hourly periods during which the average carbon monoxide concentration in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator subject to § 60.103 exceeds 0.050 percent by volume.

(3) Sulfur dioxide. (i) Any three-hour period during which the average concentration of H_2S in any fuel gas combusted in any fuel gas combustion device subject to § 60.104(a)(1) exceeds 230 mg/dscm (0.10 gr/dscf), if compliance is achieved by removing H_2S from the fuel gas before it is burned; or any three-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from any fuel gas combustion device subject to § 60.104(a)(1) exceeds the level specified in § 60.104(a)(1), if compliance is achieved by removing SO_2 from the combusted fuel gases.

(ii) Any twelve-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from any Claus sulfur recovery plant subject to § 60.104(a)(2) exceeds 250 ppm at zero percent oxygen on a dry basis if compliance with § 60.104(b) is achieved through the use of an oxidation control system or a reduction control system followed by incineration; or any twelve-hour period during which the average concentration of H_2S, or reduced sulfur compounds in the gases discharged into the atmosphere of any Claus sulfur plant subject to § 60.104(a)(2)(b) exceeds 10 ppm or 300 ppm, respectively, at zero percent oxygen and on a dry basis if compliance is achieved through the use of a reduction control system not followed by incineration.

6. Section 60.106 is amended as follows:

§ 60.106 Test methods and procedures.

* * * * *

(c) For the purpose of determining compliance with § 60.104(a)(1), Method 11 shall be used to determine the concentration of H_2S and Method 6 shall be used to determine the concentration of SO_2.

(1) If Method 11 is used, the gases sampled shall be introduced into the sampling train at approximately atmospheric pressure. Where refinery fuel gas lines are operating at pressures substantially above atmosphere, this may be accomplished with a flow control valve. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples of equal sampling time shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For most fuel gases, sample times exceeding 20 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.

(2) If Method 6 is used, Method 1 shall be used for velocity traverses and Method 2 for determining velocity and volumetric flow rate. The sampling site for determining SO_2 concentration by Method 6 shall be the same as for determining volumetric flow rate by Method 2. The sampling point in the duct for determining SO_2 concentration by Method 6 shall be at the centroid of the cross section if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than one meter from the wall. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples of equal sampling time shall constitute one run. Samples shall be taken at approximately 1-hour intervals.

(d) For the purpose of determining compliance with § 60.104(a)(2), Method 6 shall be used to determine the concentration of SO_2 and Method 15 shall be used to determine the concentration of H_2S and reduced sulfur compounds.

(1) If Method 6 is used, the procedure outlined in paragraph (c)(2) of this section shall be followed except that each run shall span a minimum of four consecutive hours of continuous sampling. A number of separate samples may be taken for each run, provided the total sampling time of these samples adds up to a minimum of four consecutive hours. Where more than one sample is used, the average SO_2 concentration for the run shall be calculated as the time weighted average of the SO_2 concentration for each sample according to the formula:

$$C_R=\sum_{i=1}^{N} C_{S_i}\frac{t_{S_i}}{T}$$

Where:

C_R = SO_2 concentration for the run.
N = Number of samples.
C_{S_i} = SO_2 concentration for sample i.
t_{S_i} = Continuous sampling time of sample i.
T = Total continuous sampling time of all N samples.

(2) If Method 15 is used, each run shall consist of 16 samples taken over a minimum of three hours. The sampling point shall be at the centroid of the cross section of the duct if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than 1 meter from the wall. To insure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3 liters/minute (0.1 ft^3/min). The SO_2 equivalent for each run shall be calculated as the arithmetic average of the SO_2 equivalent of each sample during the run. Reference Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 15. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. Each run shall span a minimum of four consecutive hours of continuous sampling. A number of separate samples may be taken for each run provided the total sampling time of these samples adds up to a minimum of four consecutive hours. Where more than one sample is used, the average moisture content for the run shall be calculated as the time weighted average of the moisture content of each sample according to the formula:

$$B_{wo}=\sum_{i=1}^{N} B_{oi}\left[\frac{t_{si}}{T}\right]$$

B_{wo} = Proportion by volume of water vapor in the gas stream for the run.
N = Number of samples.
B_{oi} = Proportion by volume of water vapor in the gas stream for the sample i.
t_{si} = Continuous sampling time for sample i.
T = Total continuous sampling time of all N samples.

(Sec. 114 of the Clean Air Act, as amended [42 U.S.C. 7414]).

* * * * *

APPENDIX A—REFERENCE METHODS

7. Appendix A is amended by adding a new reference method as follows:

METHOD 15. DETERMINATION OF HYDROGEN SULFIDE, CARBONYL SULFIDE, AND CARBON DISULFIDE EMISSIONS FROM STATIONARY SOURCES

INTRODUCTION

The method described below uses the principle of gas chromatographic separation and flame photometric detection (FPD). Since there are many systems or sets of operating conditions that represent usable methods of determining sulfur emissions, all systems which employ this principle, but differ only in details of equipment and operation, may be used as alternative methods, provided that the criteria set below are met.

1. Principle and applicability

1.1 Principle. A gas sample is extracted from the emission source and diluted with clean dry air. An aliquot of the diluted sample is then analyzed for hydrogen sulfide (H_2S), carbonyl sulfide (COS), and carbon disulfide (CS_2) by gas chromatographic (GC) separation and flame photometric detection (FPD).

1.2 Applicability. This method is applicable for determination of the above sulfur compounds from tail gas control units of sulfur recovery plants.

2. Range and sensitivity

2.1 Range. Coupled with a gas chromtographic system utilizing a 1-milliliter sample size, the maximum limit of the FPD for each sulfur compound is approximately 10 ppm. It may be necessary to dilute gas samples from sulfur recovery plants hundredfold (99:1) resulting in an upper limit of about 1000 ppm for each compound.

2.2 The minimum detectable concentration of the FPD is also dependent on sample size and would be about 0.5 ppm for a 1 ml sample.

3. Interferences

3.1 Moisture Condensation. Moisture condensation in the sample delivery system, the analytical column, or the FPD burner block can cause losses or interferences. This potential is eliminated by heating the sample line, and by conditioning the sample with dry dilution air to lower its dew point below the operating temperature of the GC/FPD analytical system prior to analysis.

3.2 Carbon Monoxide and Carbon Dioxide. CO and CO_2 have substantial desensitizing effects on the flame photometric detector even after 9:1 dilution. (Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluding CO and CO_2 before any of the sulfur compounds to be measured.) Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without CO_2 in the diluent gas. The CO_2 level should be approximately 10 percent for the case with CO_2 present. The two chromatographs should show agreement within the precision limits of section 4.1.

3.3 Elemental Sulfur. The condensation of sulfur vapor in the sampling line can lead to eventual coating and even blockage of the sample line. This problem can be eliminated along with the moisture problem by heating the sample line.

4. Precision

4.1 Calibration Precision. A series of three consecutive injections of the same calibration gas, at any dilution, shall produce results which do not vary by more than ±13 percent from the mean of the three injections.

4.2 Calibration Drift. The calibration drift determined from the mean of three injections made at the beginning and end of any 8-hour period shall not exceed ±5 percent.

5. Apparatus

5.1.1 Probe. The probe must be made of inert material such as stainless steel or glass. It should be designed to incorporate a filter and to allow calibration gas to enter the probe at or near the sample entry point. Any portion of the probe not exposed to the stack gas must be heated to prevent moisture condensation.

5.1.2 The sample line must be made of Teflon,[1] no greater than 1.3 cm (½ in) inside diameter. All parts from the probe to the dilution system must be thermostatically heated to 120° C.

5.1.3 Sample Pump. The sample pump shall be a leakless Teflon coated diaphragm type or equivalent. If the pump is upstream of the dilution system, the pump head must be heated to 120° C.

5.2 Dilution System. The dilution system must be constructed such that all sample contacts are made of inert material (e.g. stainless steel or Teflon). It must be heated to 120° C and be capable of approximately a 9:1 dilution of the sample.

5.3 Gas Chromatograph. The gas chromatograph must have at least the following components:

5.3.1 Oven. Capable of maintaining the separation column at the proper operating temperature ±1° C.

5.3.2 Temperature Gauge. To monitor column oven, detector, and exhaust temperature ±1° C.

5.3.3 Flow System. Gas metering system to measure sample, fuel, combustion gas, and carrier gas flows.

5.3.4 Flame Photometric Detector.

5.3.4.1 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

5.3.4.2 Power Supply. Capable of delivering up to 750 volts.

5.3.4.3 Recorder. Compatible with the output voltage range of the electrometer.

5.4 Gas Chromatograph Columns. The column system must be demonstrated to be capable of resolving three major reduced sulfur compounds: H_2S, COS, and CS_2.

To demonstrate that adequate resolution has been achieved the tester must submit a chromatograph of a calibration gas containing all three reduced sulfur compounds in the concentration range of the applicable standard. Adequate resolution will be defined as base line separation of adjacent peaks when the amplifier attenuation is set so that the smaller peak is at least 50 percent of full scale. Base line separation is defined as a return to zero ±5 percent in the interval between peaks. Systems not meeting this criteria may be considered alternate methods subject to the approval of the Administrator.

5.5.1 Calibration System. The calibration system must contain the following components.

5.5.2 Flow System. To measure air flow over permeation tubes at ±2 percent. Each flowmeter shall be calibrated after a complete test series with a wet test meter. If the flow measuring device differs from the wet test meter by 5 percent, the completed test shall be discarded. Alternatively, the tester may elect to use the flow data that would yield the lowest flow measurement. Calibration with a wet test meter before a test is optional.

5.5.3 Constant Temperature Bath. Device capable of maintaining the permeation tubes at the calibration temperature within ±1.1° C.

5.5.4 Temperature Gauge. Thermometer or equivalent to monitor bath temperature within ±1° C.

6. Reagents

6.1 Fuel. Hydrogen (H_2) prepurified grade or better.

6.2 Combustion Gas. Oxygen (O_2) or air, research purity or better.

6.3 Carrier Gas. Prepurified grade or better.

6.4 Diluent. Air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons.

6.5 Calibration Gases. Permeation tubes, one each of H_2S, COS, and CS_2, gravimetrically calibrated and certified at some convenient operating temperature. These tubes consist of hermetically sealed FEP Teflon tubing in which a liquified gaseous substance is enclosed. The enclosed gas permeates through the tubing wall at a constant rate. When the temperature is constant, calibration gases covering a wide range of known concentrations can be generated by varying and accurately measuring the flow rate of diluent gas passing over the tubes. These calibration gases are used to calibrate the GC/FPD system and the dilution system.

7. Pretest Procedures

The following procedures are optional but would be helpful in preventing any problem which might occur later and invalidate the entire test.

7.1 After the complete measurement system has been set up at the site and deemed to be operational, the following procedures should be completed before sampling is initiated.

7.1.1 Leak Test. Appropriate leak test procedures should be employed to verify the integrity of all components, sample lines, and connections. The following leak test procedure is suggested: For components upstream of the sample pump, attach the probe end of the sample line to a manometer or vacuum gauge, start the pump and pull greater than 50 mm (2 in.) Hg vacuum, close off the pump outlet, and then stop the pump and ascertain that there is no leak for 1 minute. For components after the pump, apply a slight positive pressure and check for leaks by applying a liquid (detergent in water, for example) at each joint. Bubbling indicates the presence of a leak.

7.1.2 System Performance. Since the complete system is calibrated following each test, the precise calibration of each component is not critical. However, these components should be verified to be operating properly. This verification can be performed by observing the response of flowmeters or of the GC output to changes in flow rates or calibration gas concentrations and ascertaining the response to be within predicted limits. If any component or the complete system fails to respond in a normal and predictable manner, the source of the discrepancy should be identifed and corrected before proceeding.

8. Calibration

Prior to any sampling run, calibrate the system using the following procedures. (If more than one run is performed during any 24-hour period, a calibration need not be performed prior to the second and any subsequent runs. The calibration must, however, be verified as prescribed in section 10, after the last run made within the 24-hour period.)

8.1 General Considerations. This section outlines steps to be followed for use of the GC/FPD and the dilution system. The procedure does not include detailed instructions because the operation of these systems is complex, and it requires an understanding of the individual system being used. Each system should include a written operating manual describing in detail the operating procedures associated with each component in the measurement system. In addition, the operator shuld be familiar with the operating principles of the components; particularly the GC/FPD. The citations in the Bibliography at the end of this method are recommended for review for this purpose.

8.2 Calibration Procedure. Insert the permeation tubes into the tube chamber. Check the bath temperature to assure agreement with the calibration temperature of the tubes within ±0.1°C. Allow 24 hours for the tubes to equilibrate. Alternatively equilibration may be verified by injecting samples of calibration gas at 1-hour intervals. The permeation tubes can be assumed to have reached equilibrium when consecutive hourly samples agree within the precision limits of section 4.1.

Vary the amount of air flowing over the tubes to produce the desired concentrations for calibrating the analytical and dilution systems. The air flow across the tubes must at all times exceed the flow requirement of the analytical systems. The concentration in parts per million generated by a bube containing a specific permeant can be calculated as follows:

$$C = K \times P_r / ML$$

Equation 15-1

where:

C = Concentration of permeant produced in ppm.

P_r = Permeation rate of the tube in μg/min.

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[1] Mention of trade names or specific products does not constitute an endorsement by the Environmental Protection Agency.

M = Molecular weight of the permeant: g/g-mole.
L = Flow rate, l/min, of air over permeant @ 20°C, 760 mm Hg.
K = Gas constant at 20°C and 760 mm Hg = 24.04 l/g mole.

8.3 Calibration of analysis system. Generate a series of three or more known concentrations spanning the linear range of the FPD (approximately 0.05 to 1.0 ppm) for each of the four major sulfur compounds. Bypassing the dilution system, inject these standards in to the GC/FPD analyzers and monitor the responses. Three injects for each concentration must yield the precision described in section 4.1. Failure to attain this precision is an indication of a problem in the calibration or analytical system. Any such problem must be identified and corrected before proceeding.

8.4 Calibration Curves. Plot the GC/FPD response in current (amperes) versus their causative concentrations in ppm on log-log coordinate graph paper for each sulfur compound. Alternatively, a least squares equation may be generated from the calibration data.

8.5 Calibration of Dilution System. Generate a know concentration of hydrogen sulfied using the permeation tube system. Adjust the flow rate of diluent air for the first dilution stage so that the desired level of dilution is approximated. Inject the diluted calibration gas into the GC/FPD system and monitor its response. Three injections for each dilution must yield the precision described in section 4.1. Failure to attain this precision in this step is an indication of a problem in the dilution system. Any such problem must be identified and corrected before proceeding. Using the calibration data for H_2S (developed under 8.3) determine the diluted calibration gas concentration in ppm. Then calculate the dilution factor as the ratio of the calibration gas concentration before dilution to the diluted calibration gas concentration determined under this paragraph. Repeat this procedure for each stage of dilution required. Alternatively, the GC/FPD system may be calibrated by generating a series of three or more concentrations of each sulfur compound and diluting these samples before injecting them into the GC/FPD system. This data will then serve as the calibration data for the unknown samples and a separate determination of the dilution factor will not be necessary. However, the precision requirements of section 4.1 are still applicable.

9. Sampling and Analysis Procedure

9.1 Sampling. Insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Begin sampling and dilute the sample approximately 9:1 using the dilution system. Note that the precise dilution factor is that which is determined in paragraph 8.5. Condition the entire system with sample for a minimum of 15 minutes prior to commencing analysis.

9.2 Analysis. Aliquots of diluted sample are injected into the GC/FPD analyzer for analysis.

9.2.1 Sample Run. A sample run is composed of 16 individual analyses (injects) performed over a period of not less than 3 hours or more than 6 hours.

9.2.2 Observation for Clogging of Probe. If reductions in sample concentrations are observed during a sample run that cannot be explained by process conditions, the sampling must be interrupted to determine if the sample probe is clogged with particulate matter. If the probe is found to be clogged, the test must be stopped and the results up to that point discarded. Testing may resume after cleaning the probe or replacing it with a clean one. After each run, the sample probe must be inspected and, if necessary, dismantled and cleaned.

10. Post-Test Procedures

10.1 Sample Line Loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ±20 percent, must be introduced into the sampling system at the opening of the probe in sufficient quantities to ensure that there is an excess of sample which must be vented to the atmosphere. The sample must be transported through the entire sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss. A sampling system loss of more than 20 percent is unacceptable. Sampling losses of 0-20 percent must be corrected by dividing the resulting sample concentration by the fraction of recovery. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.

10.2 Recalibration. After each run, or after a series of runs made within a 24-hour period, perform a partial recalibration using the procedures in section 8. Only H_2S (or other permeant) need be used to recalibrate the GC/FPD analysis system (8.3) and the dilution system (8.5).

10.3 Determination of Calibration Drift. Compare the calibration curves obtained prior to the runs, to the calibration curves obtained under paragraph 10.1. The calibration drift should not exceed the limits set forth in paragraph 4.2. If the drift exceeds this limit, the intervening run or runs should be considered not valid. The tester, however, may instead have the option of choosing the calibration data set which would give the highest sample values.

11. Calculations

11.1 Determine the concentrations of each reduced sulfur compound detected directly from the calibration curves. Alternatively, the concentrations may be calculated using the equation for the least squares line.

11.2 Calculation of SO_2 Equivalent. SO_2 equivalent will be determined for each analysis made by summing the concentrations of each reduced sulfur compound resolved during the given analysis.

$$SO_2 \text{ equivalent} = \Sigma(H_2S,\ COS,\ 2\ CS_2)d$$

Equation 15-2

where:
SO_2 equivalent = The sum of the concentration of each of the measured compounds (COS, H_2S, CS_2) expressed as sulfur dioxide in ppm.
H_2S = Hydrogen sulfide, ppm.
COS = Carbonyl sulfide, ppm.
CS_2 = Carbon disulfide, ppm.
d = Dilution factor, dimensionless.

11.3 Average SO_2 equivalent will be determined as follows:

$$\text{Average } SO_2 \text{ equivalent} = \frac{\sum_{i=1}^{N} SO_2 \text{ equiv.}_i}{N\,(1 - Bwo)}$$

Equation 15-3

where:
Average SO_2 equivalent$_i$ = Average SO_2 equivalent in ppm, dry basis.
Average SO_2 equivalent$_i$ = SO_2 in ppm as determined by Equation 15-2.
N = Number of analyses performed.
Bwo = Fraction of volume of water vapor in the gas stream as determined by Method 4—Determination of Moisture in Stack Gases (36 FR 24887).

12. Example System

Described below is a system utilized by EPA in gathering NSPS data. This system does not now reflect all the latest developments in equipment and column technology, but it does represent one system that has been demonstrated to work.

12.1 Apparatus.

12.1.1 Sample System.

12.1.1.1 Probe. Stainless steel tubing, 6.35 mm (¼ in.) outside diameter, packed with glass wool.

12.1.1.2 Sample Line. ⁵⁄₁₆ inch inside diameter Teflon tubing heated to 120° C. This temperature is controlled by a thermostatic heater.

12.1.1.3 Sample Pump. Leakless Teflon coated diaphragm type or equivalent. The pump head is heated to 120° C by enclosing it in the sample dilution box (12.2.4 below).

12.1.2 Dilution System. A schematic diagram of the dynamic dilution system is given in Figure 15-2. The dilution system is constructed such that all sample contacts are made of inert materials. The dilution system which is heated to 120° C must be capable of a minimum of 9:1 dilution of sample. Equipment used in the dilution system is listed below:

12.1.2.1 Dilution Pump. Model A-150 Kohmyhr Teflon positive displacement type, nonadjustable 150 cc/min. ±2.0 percent, or equivalent, per dilution stage. A 9:1 dilution of sample is accomplished by combining 150 cc of sample with 1350 cc of clean dry air as shown in Figure 15-2.

12.1.2.2 Valves. Three-way Teflon solenoid or manual type.

12.1.2.3 Tubing. Teflon tubing and fittings are used throughout from the sample probe to the GC/FPD to present an inert surface for sample gas.

12.1.2.4 Box. Insulated box, heated and maintained at 120° C, of sufficient dimensions to house dilution apparatus.

12.1.2.5 Flowmeters. Rotameters or equivalent to measure flow from 0 to 1500 ml/min. ±1 percent per dilution stage.

12.1.3.0 Gas Chromatograph.

12.1.3.1 Column—1.83 m (6 ft.) length of Teflon tubing, 2.16 mm (0.085 in.) inside diameter, packed with deactivated silica gel, or equivalent.

12.1.3.2 Sample Valve. Teflon six port gas sampling valve, equipped with a 1 ml sample loop, actuated by compressed air (Figure 15-1).

12.1.3.3 Oven. For containing sample valve, stripper column and separation column. The oven should be capable of maintaining an elevated temperature ranging from ambient to 100° C, constant within ±1° C.

12.1.3.4 Temperature Monitor. Thermocouple pyrometer to measure column oven, detector, and exhaust temperature ±1° C.

12.1.3.5 Flow System. Gas metering system to measure sample flow, hydrogen flow, oxygen flow and nitrogen carrier gas flow.

12.1.3.6 Detector. Flame photometric detector.

12.1.3.7 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

12.1.3.8 Power Supply. Capable of delivering up to 750 volts.

12.1.3.9 Recorder. Compatible with the output voltage range of the electrometer.

12.1.4 Calibration. Permeation tube system (Figure 15-3).

12.1.4.1 Tube Chamber. Glass chamber of sufficient dimensions to house permeation tubes.

12.1.4.2 Mass Flowmeters. Two mass flowmeters in the range 0-3 l/min. and 0-10 l/min. to measure air flow over permeation tubes at ±2 percent. These flowmeters shall be cross-calibrated at the beginning of each test. Using a convenient flow rate in the measuring range of both flowmeters, set and monitor the flow rate of gas over the permeation tubes. Injection of calibration gas generated at this flow rate as measured by one flowmeter followed by injection of calibration gas at the same flow rate as measured by the other flowmeter should agree within the specified precision limits. If they do not, then there is a problem with the mass flow measurement. Each mass flowmeter shall be calibrated prior to the first test with a wet test meter and thereafter at least once each year.

12.1.4.3 Constant Temperature Bath. Capable of maintaining permeation tubes at certification temperature of 30° C within ±0.1° C.

12.2 Reagents.

12.2.1 Fuel. Hydrogen (H_2) prepurified grade or better.

12.2.2 Combustion Gas. Oxygen (O_2) research purity or better.

12.2.3 Carrier Gas. Nitrogen (N_2) prepurified grade or better.

12.2.4 Diluent. Air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons, and filtered using MSA filters 46727 and 79030, or equivalent. Removal of sulfur compounds can be verified by injecting dilution air only, described in section 8.3.

12.2.5 Compressed Air. 60 psig for GC valve actuation.

12.2.6 Calibration Gases. Permeation tubes gravimetrically calibrated and certified at 30.0° C.

12.3 Operating Parameters. The operating parameters for the GC/FPD system are as follows: nitrogen carrier gas flow rate of 100 cc/min, exhaust temperature of 110° C, detector temperature 105° C, oven temperature of 40° C, hydrogen flow rate of 80 cc/minute, oxygen flow rate of 20 cc/minute, and sample flow rate of 80 cc/minute.

12.4 Analysis. The sample valve is actuated for 1 minute in which time an aliquot of diluted sample is injected onto the separation column. The valve is then deactivated for the remainder of analysis cycle in which time the sample loop is refilled and the separation column continues to be foreflushed. The elution time for each compound will be determined during calibration.

13. Bibliography

13.1 O'Keeffe, A. E. and G. C. Ortman. "Primary Standards for Trace Gas Analysis." Anal. Chem. 38,760 (1966).

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13.3 Mulick, J. D., R. K. Stevens, and R. Baumgardner. "An Analytical System Designed to Measure Multiple Malodorous Compounds Related to Kraft Mill Activities." Presented at the 12th Conference on Methods in Air Pollution and Industrial Hygiene Studies, University of Southern California, Los Angeles, Calif. April 6-8, 1971.

13.4 Devonald, R. H., R. S. Serenius, and A. D. McIntyre. "Evaluation of the Flame Photometric Detector for Analysis of Sulfur Compounds." Pulp and Paper Magazine of Canada, 73 3 (March, 1972).

13.5 Grimley, K. W., W. S. Smith, and R. M. Martin. "The Use of a Dynamic Dilution System in the Conditioning of Stack Gases for Automated Analysis by a Mobile Sampling Van." Presented at the 63rd Annual APCA Meeting in St. Louis, Mo. June 14-19, 1970.

13.6 General Reference. Standard Methods of Chemical Analysis Volume III A and B Instrumental Methods. Sixth Edition. Van Nostrand Reinhold Co.

[FR Doc. 78-6633 Filed 3-14-78; 8:45 am]

87

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 870-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to Reference Methods 1-8; Correction

AGENCY: Environmental Protection Agency.

ACTION: Correction.

SUMMARY: This document corrects typographical errors to certain Reference Methods and makes amendments to others for purposes of clarification. These Reference Methods were published as final rules in the FEDERAL REGISTER for Thursday, 42 FR 41754, August 18, 1977, in FR Doc. 77-13608.

EFFECTIVE DATE: March 23, 1978.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: After publication of revisions to Reference Methods 1-8 on August 18, 1977, we found many typographical errors. We also received comments which showed that the procedures in Reference Methods 1, 4, 6, and 7 needed additional clarification or revision. Additional explanation of the procedures to be used are provided by this correction notice. In addition to the errors in the methods themselves, two typographical errors were discovered in the preamble. On page 41754, under "Method 7," the phrase "variable wave length" is corrected to read "single and double-beam." On page 41755, under "Method 8," the word "content" (in point No. 4) is corrected to read "components."

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis.

Dated: March 13, 1978.

DAVID A. HAWKINS,
Assistant Administrator for Air and Waste Management.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

APPENDIX A—REFERENCE METHODS

In Method 1 of Appendix A, Sections 2.3.1, 2.3.2, and 2.4 and Table 1-1 are amended as follows:

1. In Section 2.3.1, the word "adcording" in the second line is corrected to read "according."

2. In Section 2.3.2, insert after the first paragraph the following:

If the tester desires to use more than the minimum number of traverse points, expand the "minimum number of traverse points" matrix (see Table 1-1) by adding the extra traverse points along one or the other or both legs of the matrix; the final matrix need not be balanced. For example, if a 4x3 "minimum number of points" matrix were expanded to 36 points, the final matrix could be 9x4 or 12x3, and would not necessarily have to be 6x6. After constructing the final matrix, divide the stack cross-section into as many equal rectangular, elemental areas as traverse points, and locate a traverse point at the centroid of each equal area.

3. In Section 2.4, the word "travrse" in the fifteenth line of the second paragraph is corrected to read "traverse."

4. In Table 1-1, move the words "Number of traverse points" to the left, so that they are centered above the numbers listed in the left-hand column.

In Method 2 of Appendix A, Sections 2.1, 2.2, 2.4, 3.2, 4.1, 4.1.2, 4.1.4.1, 4.1.5.2, and 6 are amended as follows;

1. In Section 2.1, "±" is inserted in front of the "5 percent" in the fourteenth line of the third paragraph.

2. In Section 2.2, "measuremen t" in the next-to-the last line of the first paragraph is corrected to read "measurement."

3. In Section 2.4, "Type X" in the fifth line is corrected to read "Type S."

4. In Section 3.2, "ma" in the first line is corrected to read "ma-."

5. In Section 4.1, "R_1" in the seventh line of the second paragraph is replaced with "D_n."

6. In Section 4.1.2, "B." is inserted between the words "other," and "Calibration."

7. In Section 4.1.4.1, "$C_{p(s)}$=Type S pitot tube coefficient" is corrected to read "$C_{p(s)}$=Type S pitot tube coefficient."

8. In Section 4.1.5.2, the words "pitot-nozzel" in the third line are corrected to read "pitot-nozzle."

9. In Section 6, Citations 9, 13, and 18 are amended as follows:

a. In No. 9, the word "Tiangle" is corrected to read "Triangle."

b. In No. 13, the "s" in "Techniques" is deleted.

c. In No. 18, the word "survey" is corrected to read "Survey."

In Method 3 of Appendix A, Sections 1.2, 3.2.4, 4.2.6.2, 6.2, and 7 are amended as follows:

1. In Section 1.2, the title ", U. S. Environmental Protection Agency." is inserted at the end of the second paragraph.

2. In Section 3.2.4, "CO" in the tenth line is corrected to read "CO_2."

3. In Section 4.2.6.2(b), the phrase "or equal to" is inserted between "than" and "15.0."

4. In Section 6.2, Equation 3-1 is corrected to read as follows:

$$\%EA=\left[\frac{\%O_2-0.5\,\%CO}{0.264\,\%N_2-(\%O_2-0.5\,\%CO)}\right]100$$

5. In Section 7, Bibliography, No. 2, the word "with" is inserted between the words "Sampling" and "Plastic."

In Method 4 of Appendix A, Sections 2.1.2, 2.2.1, 2.2.3, 2.3.1, 3.1.8, 3.2.1, 3.3.1, 3.3.3, 3.3.4, and Figure 4-2 are amended as follows:

1. In Section 2.1.2, the word "neasurement" in the third line of the third paragraph is corrected to read "measurement."

2. In Section 2.2.1, the word "travers" in the sixth line is corrected to read "traverse."

3. In Section 2.2.3, the work "eak" in the last sentence is corrected to read "leak."

4. In Figure 4-2, the word "ocation" in the second line on top of the figure, is corrected to read "Location."

5. In Section 2.3.1, "M_w" is changed to read "M_s," and "P_w" is changed to read "ρ_w."

6. In Section 3.1.8, "31 pm" is corrected to read "3 1pm".

7. In Section 3.2.1, delete all of first paragraph except the first sentence and insert the following:

Leak check the sampling train as follows: Temporarily insert a vacuum gauge at or near the probe inlet; then, plug the probe inlet and pull a vacuum of at least 250 mm Hg (10 in. Hg). Note, the time rate of change of the dry gas meter dial; alternatively, a rotameter (0-40 cc/min) may be temporarily attached to the dry gas meter outlet to determine the leakage rate. A leak rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE.—Carefully release the probe inlet plug before turning off the pump.

8. In Section 3.3.1, add the following definition to the list:

Y = Dry gas meter calibration factor.

Also, "σ_w" is corrected to read "ρ_w".

9. In Section 3.3.3, Equation 4-6 is corrected to read as follows:

$$V_{m(std)}=V_m\,Y\left(\frac{P_m}{P_{std}}\right)\left(\frac{T_{std}}{T_m}\right)=K_2\,Y\,\frac{V_m\,P_m}{T_m}$$

10. In Section 3.3.4, Equation 4-7 is corrected to read as follows:

$$B_{ws}=\frac{V_{wc(std)}}{V_{wc(std)}+V_{m(std)}}+B_{wm}=\frac{V_{wc(std)}}{V_{wc(std)}+V_{m(std)}}+(0.025)$$

In Method 5 of Appendix A, Sections 2.1.1, 2.2.4, 4.1.2, 4.1.4.2, 4.2, 6.1, 6.3, 6.11.1, and 6.11.2 are amended as follows:

1. In Section 2.1.1, the word "proble" in the fourth line is corrected to read "probe."

2. In Section 2.2.4, "polo-" is corrected to read "poly-".

3. In Section 4.1.2, the sentence "The sampling time at each point shall be the same." is inserted at the end of the fifth paragraph.

4. In Section 4.1.4.2, the word "It" in the seventh line is corrected to read "it."

5. In Section 4.2, the word "nylon" in the seventh, ninth, and thirteenth paragraphs is corrected to read "Nylon."

6. In Section 6.1 Nomenclature, "C_a = Acetone blank residue concentrations, mg/g" is corrected to read "C_a = Acetone blank residue concentration, mg/g" and "V_a" is changed to read "v_a."

7. In Section 6.3, page 41782, "m_1=0.3858 °K/mm Hg for metric units" is corrected to read "K_1=0.3858 °K/mm Hg for metric units."

8. In Section 6.11.1, Equation 5-7 is corrected to read as follows:

$$I=\frac{100\,T_s\left[K_3\,V_{lc}+(V_m\,Y/T_m)\,(P_{bar}+\Delta H/13.6)\right]}{60\,\theta\,v_s\,P_s\,A_n}$$

9. In Section 6.11.2, the second form of Equation 5-8 is corrected to read as follows:

$$=K_4\,\frac{T_s\,V_{m(std)}}{P_s\,v_s\,A_n\,\theta\,(1-B_{ws})}$$

In Method 6 of Appendix A, Sections 2.1, 2.1.6, 2.1.7, 2.1.8, 2.1.11, 2.1.12, 2.3.2, 3.3.4, 4.1.2, 4.1.3, and 5.1.1 are amended as follows:

1. In Section 2.1, the word "perioxide" in the fourth line of the second paragraph is corrected to read "peroxide."

2. In Section 2.1.6, the word "silliac" in the third line is corrected to read "sillica."

3. In Section 2.1.7, the word "value", which appears twice is corrected to read "valve."

4. In Section 2.1.8, the word "disphragm" is corrected to read "diaphragm" and the word "surge" is inserted between the words "small" and "tank."

5. In Section 2.1.11, the word "ameroid" is corrected to read "aneroid."

6. In Section 2.1.12, the phrase "and Rotameter." is inserted after the phrase "Vacuum Gauge" and the phrase "and 0–40 cc/min rotameter" is inserted between the words "gauge" and ", to."

7. In Section 2.3.2, the phrase "and 100-ml size" is corrected to read "and 1000-ml size."

8. In Section 3.3.4, the word "sopropanol" in the fourth line is corrected to read "isopropanol."

9. In Section 4.1.2, delete the last sentence of the last paragraph. Also delete the second paragraph and replace it with the following paragraphs:

Temporarily attach a suitable (e.g., 0–40 cc/min) rotameter to the outlet of the dry gas meter and place a vacuum gauge at or near the probe inlet. Plug the probe inlet, pull a vacuum of at least 250 mm Hg (10 in. Hg), and note the flow rate as indicated by the rotameter. A leakage rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE: Carefully release the probe inlet plug before turning off the pump.

It is suggested (not mandatory) that the pump be leak-checked separately, either prior to or after the sampling run. If done prior to the sampling run, the pump leak-check shall precede the leak check of the sampling train described immediately above; if done after the sampling run, the pump leak-check shall follow the train leak-check. To leak check the pump, proceed as follows: Disconnect the drying tube from the probe-impinger assembly. Place a vacuum gauge at the inlet to either the drying tube or the pump, pull a vacuum of 250 mm (10 in.) Hg, plug or pinch off the outlet of the flow meter and then turn off the pump. The vacuum should remain stable for at least 30 seconds.

10. In Section 4.1.3, the sentence "If a leak is found, void the test run" on the sixteenth line is corrected to read

"If a leak is found, void the test run, or use procedures acceptable to the Administrator to adjust the sample volume for the leakage."

11. In Section 5.1.1, the word "or" on the sixth line is corrected to read "of."

In Method 7 of Appendix A, Sections 2.3.2, 2.3.7, 4.2, 4.3, 5.2.1, 5.2.2, 6 and 7 are amended as follows:

1. In Section 2.3.2, a semicolon replaces the comma between the words "step" and "the."

2. In Section 2.3.7, the phrase "(one for each sample)" in the first line is corrected to read "(one for each sample and each standard)."

3. In Section 4.2, the letter "n" in the seventh line is corrected to read "in."

4. In Section 4.3, the word "poylethylene" in the seventeenth line is corrected to read "polyethylene."

5. In Section 5.2.1, delete the entire section and insert the following:

Optimum Wavelength Determination. Calibrate the wavelength scale of the spectrophotometer every 6 months. The calibration may be accomplished by using an energy source with an intense line emission such as a mercury lamp, or by using a series of glass filters spanning the measuring range of the spectrophotometer. Calibration materials are available commercially and from the National Bureau of Standards. Specific details on the use of such materials should be supplied by the vendor; general information about calibration techniques can be obtained from general reference books on analytical chemistry. The wavelength scale of the spectrophotometer must read correctly within ± 5 nm at all calibration points; otherwise, the spectrophotometer shall be repaired and recalibrated. Once the wavelength scale of the spectrophotometer is in proper calibration, use 410 nm as the optimum wavelength for the measurement of the absorbance of the standards and samples.

Alternatively, a scanning procedure may be employed to determine the proper measuring wavelength. If the instrument is a double-beam spectrophotometer, scan the spectrum between 400 and 415 nm using a 200 µg NO_2 standard solution in the sample cell and a blank solution in the reference cell. If a peak does not occur, the spectrophotometer is probably malfunctioning and should be repaired. When a peak is obtained within the 400 to 415 nm range, the wavelength at which this peak occurs shall be the optimum wavelength for the measurement of absorbance of both the standards and the samples. For a single-beam spectrophotometer, follow the scanning procedure described above, except that the blank and standard solutions shall be scanned separately. The optimum wavelength shall be the wavelength at which the maximum difference in absorbance between the standard and the blank occurs.

6. In Section 5.2.2, delete the first seven lines and insert the following:

Determination of Spectrophotometer Calibration Factor K_c. Add 0.0 ml, 2 ml, 4 ml, 6 ml, and 8 ml of the KNO_3 working standard solution (1 ml = 100 µg NO_2) to a series of five 50-ml volumetric flasks. To each flask, add 25 ml of absorbing solution, 10 ml deionized, distilled water, and sodium hydroxide (1 N) dropwise until the pH is between 9 and 12 (about 25 to 35 drops each). Dilute to the mark with deionized, distilled water. Mix thoroughly and pipette a 25-ml aliquot of each solution into a separate porcelain evaporating dish.

7. In Section 6.1, the word "Hass" in the tenth line is corrected to read "Mass."

8. In Section 7, the word "Vna" in (1) is corrected to read "Van." The word "drtermination" in (6) is corrected to read "Determination."

In Method 8 of Appendix A, Sections 1.2, 2.32, 4.1.4, 4.2.1, 4.3.2, 6.1, and 6.7.1 are amended as follows:

1. In Section 1.2, the phrase "U.S. EPA," is inserted in the fifth line of the second paragraph between the words "Administrator," and "are." Also, delete the third paragraph and insert the following:

Filterable particulate matter may be determined along with SO_2 and SO_3 (subject to the approval of the Administrator) by inserting a heated glass fiber filter between the probe and isopropanol impinger (see Section 2.1 of Method 6). If this option is chosen, particulate analysis is gravimetric only; H_2SO_4 acid mist is not determined separately.

2. In Section 2.3.2, the word "Burrette" is corrected to read "Burette."

3. In Section 4.1.4, the stars "* * *" are corrected to read as periods ". . .".

4. In Section 4.3.1, the word "het" on the eighth line of the second paragraph is corrected to read "the."

5. In Section 4.3.2, the number "40" is inserted in the fourth line between the words "Add" and "ml."

6. In Section 6.1, Nomenclature, the following are corrected to read as shown with subscripts "$C_{H_2SO_4}$, C_{SO_2}, P_{bar}, P_{std}, T_{std}, $V_{m(std)}$, and V_{soln}."

7. In Section 6.7.1, Equation 8-4 is corrected to read as follows:

$$I = \frac{100\,T_s\,[K_4\,V_{lc} + (V_m Y/T_m)(P_{bar} + \Delta H/13.6)]}{60\,\theta\,v_s\,P_s\,A_n}$$

(Secs. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

[FR Doc. 78-7686 Filed 3-22-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 57

THURSDAY, MARCH 23, 1978

88

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 841-6]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Basic Oxygen Process Furnaces: Opacity Standard

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action establishes an opacity standard for basic oxygen process furnace (BOPF) facilities. In March 1974 (39 FR 9308), EPA promulgated a standard limiting the concentration of particulate matter emissions from BOPF's, however, an opacity standard was not promulgated at that time becuase of insufficient data to define variations in visible emissions from well-controlled facilities. An opacity standard had been proposed on June 11, 1973 (38 FR 15406) and was reproposed on March 2, 1977 (42 FR 12130). Additional data have provided the basis for the opacity standard which will help insure that control equipment is properly operated and maintained. Like the concentration standard, this opacity standard applies to BOPF facilities the construction or modification of which was commenced after June 11, 1973 since both standards were proposed on that date.

EFFECTIVE DATE: April 13, 1978.

ADDRESS: The public comments received may be inspected and copies at the Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION:

Don R. Goodwin, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone No. 919-541-5271.

SUPPLEMENTARY INFORMATION:

COMMENTS

A total of 10 comment letters were received—4 from industry, 5 from governmental agencies, and 1 from an environmental interest group. The significant comments received and EPA's responses are presented here.

Three commenters expressed the need for establishing an opacity standard for fugitive emissions. Fugitive emissions occur when off gases from the furnace are not completely captured by the furnance hood (which ducts waste gases to the control device). During some operations, the fugitive emissions can be significant. The fugitive emissions escape to the atmosphere through roof monitors.

EPA recognizes that fugitive emissions from BOPF shops are an important problem. However, it was not within the scope of this evaluation to consider an opacity standard for fugitive emissions. The particulate concentration standard covers only stack emissions. The purpose of the opacity standard for stack emissions is to serve as a means for enforcement personnel to insure that the particulate matter control system is being properly operated and maintained. EPA will be reviewing the standards of performance for new BOPF's in accordance with the 1977 amendments to the Clean Air Act. This review will address the need for limits on fugitive emissions as well as any revisions of the particulate concentration and opacity standards.

It should be noted that the absence of standards for fugitive emissions under this part does not preclude the establishment of standards as part of the new source review (NSR) and prevention of significant deterioration (PSD) programs of the Agency or as part of the programs of State and local agencies.

Two commenters questioned how the standard would apply to BOPF shops that have plenums to exhaust the emissions from more than one furnace into a single control device. They reasoned that if the production cycles overlap, it would be impossible to determine when an opacity of greater than 10 percent (but less than 20 percent) was attributable to a violation by one furnace or an acceptable emission by another furnace during oxygen blowing. EPA was aware that this situation would occur during the development of the opacity standard. Several of the plants at which visible emission tests were conducted had a single control device serving more than one furnace. The furnace production cycle data were recorded and it was not difficult to correlate the opacity data with the production cycle. Enforcement personnel can evaluate a plant's operation (length of cycle, degree of overlapping, etc.) prior to completing an inspection and correctly identify probable violations from a correlation of their opacity readings with the plant's production and monitoring records. Correlation of the data and the synchronization requirements described later will prevent the enforcement problems described by the commenters. Promulgation of an unduly complex standard that addresses the peculiarities of every BOPF installation would complicate rather than simplify enforcement. Although it is unlikely that two furnaces will be simultaneously started on a blow, production data should be examined for such peculiarities before drawing any conclusions from the opacity data.

Other issues raised include the effect of oxygen "reblows" on the standard and a request for a more lenient monitoring requirement. One industry commenter claimed that there would be a "significant" number of production cycles with more than one opacity reading greater than 10 percent due to the blowing of additional oxygen (after the initial oxygen blow) into a furnace to obtain the proper composition. The opacity standard, however, is based on 73 hours of BOPF operation during which numerous reblows occurred. It was found that although the opacities could be very large at these times, they were of short enough duration that the six-minute average was still 10 percent or less.

EPA agrees with the comment that the requirement for reporting of instantaneous scrubber differential and water supply pressures that are less than 10 percent of the average maintained during the most recent performance test needs further clarification. The requirement has been revised so that any deviation of more than 10 percent over a three hour averaging period must be reported. The three hour averaging period was chosen since it is the minimum duration of a performance test. Thus instantaneous monitoring device measurements caused by routing process fluctuations will not be reported. The reports needed are the periods of time when the average scrubber pressure drop is below the level used to demonstrate compliance at the time of the performance test. In addition, the requirement for a water pressure monitor has been retained (despite the comment that it will not indicate a plugged water line) since it will perform the function of assuring that the water pumps have not shut down. A flow monitoring device was not specified because they are susceptible to plugging.

To provide for the use of certain partial combustion systems on BOPFs, new requirements have been added to the monitoring section and two clarifications added to the test methods and procedures section. A partial combustion system uses a closed hood to limit gas combustion and exhaust gas volumes. To recover combustible exhaust gases, the system may be designed to duct its emissions away from the stack to a gas holding tank during part of the steel production cycle. Steel plants in this country may begin to make more use of this approach due to its significant energy benefits. This type of control/recovery system presents two problems for enforcement personnel. First is the problem of knowing when the diversion of exhaust gases from the stack occurs. The new requirements of paragraphs (a), (b)(3), and (b)(4) of §60.143 address this question. Second is the problem of how to sample or observe stack emissions. New provisions under §60.144 clarify this question for determining the opacity of emissions (paragraph (a)(5)) and for determining the concentration of emissions (paragraph (c)).

In addition to addressing the problem posed by exhaust gas diversion, the new requirements of paragraphs (a), (b)(3), and (b)(4) of §60.143 are also designed to minimize errors in recording the time and duration of the steel production cycle for all types of BOPFs. Accurate records are essential for determining compliance with the opacity standard. Likewise the synchronization of daily logs with the chart recorders of monitoring devices is necessary for determining that acceptable operation and maintenance procedures are being used as required by paragraph (d) of §60.11.

An alternative to the manual method of synchronization under paragraph (b)(3) of §60.143 which may minimize costs of this requirement would be to have the chart recorder automatically mark the beginning and end of the steel production cycle and any period of gas diversion from the stack. Such marking could be electrically relayed from the production equipment and exhaust duct damper operation in order to be fully automatic. Source owners or operators who wish to employ this method or equivalent methods in lieu of the synchronization procedure prescribed by the regulations may submit their plans to the Administrator for approval under paragraph 60.13(i).

The concentration standard promulgated in March, 1974, applies to both top and bottom-blown BOPFs. In developing the proposed opacity standard, data from both types of BOPFs were considered. Scrubber-controlled top and bottom-blown BOPFs were demonstrated capable of meeting the opacity limits proposed and here promulgated. Thus the promulgated opacity standard applies to bottom as well as top-blown BOPFs.

Although there was no announced intentions to utilize electrostatic precipitators (ESPs) as a control device (rather than venturi scrubbers), during the development of the proposed standard, one industry commenter asserted that ESPs may become more attractive in the future, especially in the semi-arid regions of the West where the water and energy demands of scrubbers are not easily met. If a BOPF furnace is constructed with an ESP control device, the establishment of a site-specific opacity standard may be necessary. Upon request by the owner or operator of the BOPF furnace, a determination will be made by EPA pursuant to §60.11(e) if performance tests demonstrate compliance with the mass concentration standard.

Miscellaneous

It should be noted that standards of performance for new sources established under section 111 of the Act reflect emission limits achievable with the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173(2) of the Clean Air Act, requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source, unless the owner or operator demonstrates that the source cannot achieve such an emission rate. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term "best available control technology" (BACT) means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facilities through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), costs must be accorded for less weight in determining the "lowest achievable emission rate for the new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below the level required to comply with standards of performance, this technology might be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate." Furthermore, since partial combustion systems and bottom blown BOPFs have been shown to be inherently less polluting, more stringent emission limits may be placed on such sources for the purposes of defining "best available control technology" (under Prevention of Significant Deterioration regulation) and "lowest achievable emission rate" in non-attainment areas.

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under secton 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

The effective date of this regulation is (date of publication), because section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation.

The opacity standard, like the concentration standard, applies to BOPFs which commenced construction or modification after June 11, 1973. That is the date on which both standards were originally proposed. The opacity standard will add no new control burden to the sources affected, but will provide an effective means of monitoring the compliance of these facilities. The relief provided under § 60.11(e) insures that the opacity standard requires no greater reduction in emissions than the concentration standard.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: April 4, 1978.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

Subpart N—Standards of Performance for Iron and Steel Plants

1. Section 60.141 is amended by adding paragraph (c) as follows:

§ 60.141 Definitions.

* * * * *

(c) "Startup means the setting into operation for the first steel production cycle of a relined BOPF or a BOPF which has been out of production for a minimum continuous time period of eight hours.

2. Section 60.142 is amended by adding paragraph (a)(2) as follows:

§ 60.142 Standard for particulate matter.

(a) * * *

(2) Exit from a control device and exhibit 10 percent opacity or greater, except that an opacity of greater than 10 percent but less than 20 percent may occur once per steel production cycle.

(Secs. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601).)

3. A new § 60.143 is added as follows:

§ 60.143 Monitoring of operations.

(a) The owner or operator of an affected facility shall maintain a single time-measuring instrument which shall be used in recording daily the time and duration of each steel production cycle, and the time and duration of any diversion of exhaust gases from the main stack servicing the BOPF.

(b) The owner or operator of any affected facility that uses venturi scrubber emission control equipment shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±250 Pa (±1 inch water).

(2) A monitoring device for the continous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of the design water supply pressure. The monitoring device's pressure sensor or pressure tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations for the pressure sensor or tap.

(3) All monitoring devices shall be synchronized each day with the time-measuring instrument used under paragraph (a) of this section. The chart recorder error directly after synchronization shall not exceed 0.08 cm ($\frac{1}{32}$ inch).

(4) All monitoring devices shall use chart recorders which are operated at a minimum chart speed of 3.8 cm/hr (1.5 in/hr).

(5) All monitoring devices are to be recalibreated annually, and at other times as the Administrator may require, in accordance with the procedures under § 60.13(b)(3).

(c) Any owner or operator subject to requirements under paragraph (b) of this section shall report for each calendar quarter all measurements over any three-hour period that average more than 10 percent below the average levels maintained during the most recent performance test conducted under § 60.8 in which the affected facility demonstrated compliance with the standard under § 60.142(a)(1). The accuracy of the respective measurements, not to exceed the values specified in paragraphs (b)(1) and (b)(2) of this section, may be taken into consideration when determining the measurement results that must be reported.

4. Section 60.144 is amended by adding paragraphs (a)(5) and (c) as follows:

§ 60.144 Test methods and procedures.

(a) * * *

(5) Method 9 for visible emissions. For the purpose of this subpart, opacity observations taken at 15-second intervals immediately before and after a diversion of exhaust gases from the stack may be considered to be consecutive for the purpose of computing an average opacity for a six-minute period. Observations taken during a diversion shall not be used in determining compliance with the opacity standard.

* * * * *

(c) Sampling of flue gases during each steel production cycle shall be discontinued whenever all flue gases are diverted from the stack and shall be resumed after each diversion period.

(Secs. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

[FR Doc. 78-9879 Filed 4-12-78; 8:45 am]

89

Title 40—Protection of Environment

[FRL 883-6]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

Subchapter C—Air Programs

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State/Local Air Pollution Control Agencies in Arizona, California, and Nevada

AGENCY: Environmental Protection Agency.

ACTION: Final Rulemaking.

SUMMARY: The Environmental Protection Agency (EPA) is amending 40 CFR 60.4 *Address* by adding addresses of agencies to reflect new delegations of authority from EPA to certain state/local air pollution control agencies in Arizona, California, and Nevada. EPA has delegated authority to these agencies, as described in a notice appearing elsewhere in today's FEDERAL REGISTER, in order to implement and enforce the standards of performance for new stationary sources.

EFFECTIVE DATE: May 16, 1978.

FOR FURTHER INFORMATION CONTACT:

Gerald Katz (E-4-3), Environmental Protection Agency, 215 Fremont Street, San Francisco, Calif. 94105, 415-556-8005.

SUPPLEMENTARY INFORMATION: Pursuant to delegation of authority for the standards of performance for new stationary sources (NSPS) to State/Local air pollution control agencies in Arizona, California, and Nevada from March 30, 1977 to January 30, 1978, EPA is today amending 40 CFR 60.4 *Address*, to reflect these actions. A Notice announcing this delegation is published elsewhere in today's FEDERAL REGISTER. The amended § 60.4 is set forth below. It adds the address of the air pollution control agencies, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within these agencies' jurisdictions.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation actions which are reflected in this administrative amendment were effective on the dates of delegation and it serves no purpose to delay the technical change on these additions of the air pollution control agencies' addresses to the Code of Federal Regulations.

(Sec. 111, Clean Air Act, as amended (42 U.S.C. 7411).)

Dated: April 5, 1978.

SHEILA M. PRINDIVILLE,
Acting Regional Administrator, Environmental Protection Agency, Region IX.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraphs D, F, and DD to read as follows:

§ 60.4 Address.

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(b) * * *

(D) Arizona:

Maricopa County Department of Health Services, Bureau of Air Pollution Control, 1825 East Roosevelt Street, Phoenix, AZ 85006.

Pima County Health Department, Air Quality Control District, 151 West Congress, Tucson, AZ 85701.

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(F) California:

Bay Area Air Pollution Control District, 939 Ellis Street, San Francisco, CA 94109.

Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531.

Fresno County Air Pollution Control District, 515 S. Cedar Avenue, Fresno, CA 93702.

Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501.

Kern County Air Pollution Control District, 1700 Flower Street (P.O. Box 997), Bakersfield, CA 93302.

Madera County Air Pollution Control District, 135 W. Yosemite Avenue, Madera, CA 93637.

Mendocino County Air Pollution Control District, County Courthouse, Ukiah, CA 94582.

Monterey Bay Unified Air Pollution Control District, 420 Church Street (P.O. Box 487), Salinas, CA 93901.

Northern Sonoma County Air Pollution Control District, 3313 Chanate Road, Santa Rosa, CA 95404.

Sacramento County Air Pollution Control District, 3701 Branch Center Road, Sacramento, CA 95827.

San Diego County Air Pollution Control District, 9150 Chesapeake Drive, San Diego, CA 92123.

San Joaquin County Air Pollution Control District, 1601 E. Hazelton Street (P.O. Box 2009), Stockton, CA 95201.

Santa Barbara County Air Pollution Control District, 4440 Calle Real, Santa Barbara, CA 93110.

Shasta County Air Pollution Control District, 1855 Placer Street, Redding, CA 96001.

South Coast Air Quality Management District, 9420 Telstar Avenue, El Monte, CA 91731.

Stanislaus County Air Pollution Control District, 820 Scenic Drive, Modesto, CA 95350.

Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093.

Ventura County Air Pollution Control District, 625 E. Santa Clara Street, Ventura, CA 93001.

* * * * *

(DD) Nevada:

Nevada Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, NV 89710.

Clark County County District Health Department, Air Pollution Control Division, 625 Shadow Lane, Las Vegas, NV 89106.

Washoe County District Health Department, Division of Environmental Protection, 10 Kirman Avenue, Reno, NV 89502.

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[FR Doc. 78-13011 Filed 5-15-78; 8:45 am]

238

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Title 40—Protection of the Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 907-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Grain Elevators

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The standards limit emissions of particulate matter from new, modified, and reconstructed grain elevators. The standards implement the Clean Air Act and are based on the Administrator's determination that emissions from grain elevators contribute significantly to air pollution. The intended effect of these standards is to require new, modified, and reconstructed grain elevators to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, environmental and energy impacts.

EFFECTIVE DATE: August 3, 1978.

ADDRESSES: Copies of the standards support documents are available on request from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711, telephone 919-541-2777 or (FTS) 629-2777. The requester should specify "Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Grain Elevator Industry," (EPA-450-77-001a) and/or "Standards Support and Environmental Impact Statement, Volume 2: Promulgated Standards of Performance for Grain Elevator Industry," (EPA-450/2-77-001b). Copies of all comment letters received from interested persons participating in this rulemaking are available for inspection and copying during normal business hours at EPA's Public Information Reference Unit, Room 2922, EPA Library, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On January 13, 1977, standards of performance were proposed for the grain elevator industry (42 FR 2842) under the authority of section 111 of the Clean Air Act. Public comments were requested on the proposal in the FEDERAL REGISTER publication. Approximately 2,000 comments were received from grain elevator operators, vendors of equipment, Congressmen, State and local air pollution control agencies, other Federal agencies, and individual U.S. citizens. Most of these comments reflected a general misunderstanding of the proposed standards and were very general in nature. A number of comments, however, contained a significant amount of useful data and information. Due to the time required to review these comments, the standards were suspended on June 24, 1977. This action was necessary to avoid creating legal uncertainties for those grain elevator operators who might have undertaken various expansion or alteration projects before promulgation of final standards.

On August 7, 1977, Congress amended the Clean Air Act. These amendments contained a provision specifically exempting country grain elevators with less than 2.5 million bushels of grain storage capacity from standards of performance developed under section 111 of the Act.

Following review of the public comments, a draft of the final standards was developed consistent with the adopted amendments to the Clean Air Act. A report responding to the major issues raised in the public comments and containing the draft final standards was mailed on August 15, 1977, to each individual, agriculture association, equipment vendor, State and local government, and member of Congress who submitted comments. Comments were requested on the draft final standards by October 15, 1977. One hundred comments were received, and the final standards reflect a thorough evaluation of these comments.

The proposed standards are reinstated elsewhere in this issue of the FEDERAL REGISTER.

THE STANDARDS

The promulgated standards apply only to new, modified, or reconstructed grain elevators with a permanent grain storage capacity of more than 88,100 m ^{3} (ca. 2.5 million U.S. bushels) and new, modified, or reconstructed grain storage elevators at wheat flour mills, wet corn mills, dry corn mills (human consumption), rice mills, or soybean oil extraction plants with a permanent grain storage capacity of more than 35,200 m ^{3} (ca. 1 million U.S. bushels).

The standards limit particulate matter emissions from nine types of affected facilities at grain elevators by limiting the visibility of emissions released to the atmosphere. The affected facilities are each truck loading station, truck unloading station, railcar loading station, railcar unloading station, barge or ship loading station, barge or ship unloading station, grain dryer, all grain handling operations and each emission control device.

The standards can be summarized as follows:

(a) Truck loading station—visible emissions may not exceed 10 percent opacity.

(b) Truck unloading station, railcar loading station, and railcar unloading station—visible emissions may not exceed 5 percent opacity.

(c) Ship or barge loading station—visible emissions may not exceed 20 percent opacity.

(d) Ship or barge unloading station—specified equipment or its equivalent must be used.

(e) Grain dryer—visible emissions may not exceed 0 percent opacity.

(f) All grain handling operations—visible emissions may not exceed 0 percent opacity.

(g) Emission control devices—visible emissions may not exceed 0 percent opacity; and the concentration of particulate matter in the exhaust gas discharged to the atmosphere may not exceed 0.023 g/dscm (ca. 0.01 gr/dscf).

These standards are different from those proposed in the following areas. The visible emission limits for truck unloading stations and railcar loading and unloading stations have been increased from 0 percent opacity to 5 percent opacity. The visible emission limit for barge and ship loading has been increased from 10 percent opacity during normal loading and 15 percent opacity during "topping off" loading, to 20 percent opacity during all loading operations. The applicability of the visible emission standards for column grain dryers has been narrowed from dryers with perforated plate hole sizes of greater than 0.084 inch diameter to dryers with perforated plate hole sizes of greater than 0.094 inch diameter.

The August 1977 amendments to the Clean Air Act authorize the promulgation of design, equipment, work practice, or operational standards if development of a numerical emission limit is not feasible. Numerical emission limits may not be feasible where emissions are not confined or where emissions cannot be measured due to technological or economic limitations. Observation of visible emissions at barge unloading stations led to the conclusion that a numerical emission limit is not feasible for this facility. The visible emissions data showed an extremely wide range with some 6 minute averages above 65 percent opacity. Because of this wide range of visible emissions, an opacity numerical emission limit cannot be established that would ensure the use of the best system of continuous emission reduction. An equipment standard, therefore, rather than an emission standard is being promulgated for barge and ship unloading stations.

Another change from the proposed standards is that section 60.14 (modification) of the general provisions has been clarified to ensure that only capital expenditures which are spent directly on an affected facility are used to determine whether the annual asset guideline repair allowance percentage is exceeded. The annual asset guideline repair allowance percentage has been defined to be 6.5 percent.

The remaining change from the proposed standards is that four types of alterations at grain elevators have been exempted from consideration as modifications. The exempted alterations are:

(1) The addition of gravity load-out spouts to existing grain storage or grain transfer bins.

(2) The installation of automatic grain weighing scales.

(3) Replacement of motor and drive units driving existing grain handling equipment.

(4) The installation of permanent storage capacity with no increase in hourly grain handling capacity.

Environmental and Economic Impacts

The promulgated standards will reduce uncontrolled particulate matter emission from new grain elevators by more than 99 percent and will reduce particulate matter emissions by 70 to 90 percent compared to emission limits contained in State or local air pollution regulations. This reduction in emissions will result in a significant reduction of ambient air concentration levels of particulate matter in the vicinity of grain elevators. The maximum 24-hour average ambient air particulate matter concentration at a distance of 0.3 kilometer (km) from a typical grain elevator, for example, will be reduced by 50 to 80 percent below the ambient air concentration that would result from control of emissions to the level of the typical State or local air pollution regulations.

Several of the changes to the proposed standards reduce the estimated primary impact of the proposed standards in terms of reducing emissions of particulate matter from grain elevators. The promulgated standards, for example, apply only to large grain elevators. These changes will permit more emissions of particulate matter to the atmosphere. It was estimated that the proposed standards would have reduced national particulate matter emissions by approximately 21,000 metric tons over the next 5 years; it is now estimated that the promulgated standards will reduce particulate matter emissions by 11,000 metric tons over the next 5 years.

The secondary environmental impacts associated with the promulgated standards will be a small increase in solid waste handling and disposal and a small increase in noise pollution. A relatively minor amount of particulate matter, sulfur dioxide and nitrogen oxide emissions will be discharged into the atmosphere from steam/electric power plants supplying the additional electrical energy required to operate the emission control devices needed to comply with the promulgated standards. The energy impact associated with the promulgated standards will be small and will lead to an increase in national energy consumption in 1981 by the equivalent of only 1,600 m^3 (ca. 10,000 barrels) per year of No. 6 fuel oil.

Based on information contained in the comments submitted during the public comment periods, approximately 200 grain terminal elevators and grain storage elevators at grain processing plants will be covered by the promulgated standards over the next 5 years. The total incremental costs required to control emissions at these grain elevators to comply with the promulgated standards, above the costs necessary to control emissions at these elevators to comply with State or local air pollution control regulations, is $15 million in capital costs over this 5-year period and $3 million in annualized costs in the fifth year. Based on this estimate of the national economic impact, the promulgated standards will have no significant effect on the supply and demand for grain products, or on the growth of the domestic grain industry.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register of a meeting of the National Air Pollution Control Techniques Advisory Committee. In addition, copies of the proposed standards and the Standards Support and Environmental Impact Statement (SSEIS) supporting these standards were distributed to members of the grain elevator industry and several environmental groups at the time of proposal. The public comment period extended from January 13, to May 14, 1977. During this period 1,817 comments were received from grain elevator operators, vendors of equipment, Congressmen, State and local air pollution control agencies, other Federal agencies, and individual U.S. citizens.

Due to the time required to review these comments, the proposed standards were suspended on June 24, 1977. This action was necessary to avoid creating legal uncertainties for those grain elevator operators who might have undertaken various expansion or alteration projects before promulgation of final standards.

Following review of the public comments, a draft of the final standards was developed consistent with the August, 1977, amendments to the Clean Air Act. A report responding to the major issues raised in the public comments and containing the draft final standards was mailed on August 15, 1977, to each individual, agriculture association, equipment vendor, State and local government, and member of Congress who submitted comments. Comments were requested on the draft final standards by October 15, 1977.

One hundred and one comments were received and the final standards reflect a thorough evaluation of these comments. Several comments resulted in changes to the proposed standards. A detailed discussion of the comments and changes made to the proposed standards is contained in volume 2 of the SSEIS, which was distributed along with a copy of the final standards to all interested parties prior to today's promulgation of final standards.

Significant Comments

Most of the comment letters received by EPA contained multiple comments. The most significant comments and changes made to the proposed standards are discussed below:

NEED FOR STANDARDS

Numerous commenters questioned whether grain elevators should be regulated since the industry is a small contributor to nationwide emissions of particulate matter and grain dust is not hazardous or toxic.

The standards were proposed under section 111 of the Clean Air Act. This section of the act requires that standards of performance be established for new stationary sources which contribute to air pollution. Existing sources are not affected unless they are reconstructed, or modified in such a way as to increase emissions. The overriding purpose of standards of performance is to prevent new air pollution problems from developing by requiring maximum feasible control of emissions from new, modified, or reconstructed sources at the time of their construction. This is helpful in attaining and maintaining the National Ambient Air Quality Standard (NAAQS) for suspended particulate matter.

The Report of the Committee on Public Works of the United States Senate in September 1970 (Senate Report No. 91-1196), listed grain elevators as a source for which standards of performance should be developed. In addition, a study of 200 industrial categories of sources, which were evaluated to develop a long-range plan for setting standards of performance for particulate matter, ranked grain elevators relatively high. The categories were ranked in order of priority based on potential decrease in emissions. Various grain handling operations ranked as follows: Grain processing—4; grain transfer—6; grain cleaning and screening—8; and grain drying—33. Therefore, grain elevators are a significant source of particulate matter emissions and standards of performance have been developed for this source category.

Many commenters felt, however, that it was unreasonable to require small country elevators to comply with the proposed standards because of their remote location and small amount of emissions. This sentiment was reflected in the 1977 amendments to the Clean Air Act which exempted country elevators with a grain storage capacity of less than 88,100 m^3 (ca. 2.5 million U.S. bushels) from standards of performance. Consequently, the scope of the proposed standards has been narrowed and the promulgated standards apply only to new, modified, or reconstructed facilities within grain elevators with a permanent storage capacity in excess of 88,100 m^3.

A number of commenters also felt small flour mills should not be covered by standards of performance because they are also small sources of particulate matter emissions and handle less grain than some country elevators which were exempted from standards of performance by the 1977 amendments to the Clean Air Act. These processors are considered to be relatively small sources of particulate matter emissions that are best regulated by State and local regulations. Consequently, grain storage elevators at wheat flour mills, wet corn mills, dry corn mills (human consumption), rice mills, and soybean oil extraction plants with a storage capacity of less than 35,200 m^3 (ca. 1 million U.S. bushels) of grain are exempt from the promulgated standards.

With regard to the hazardous nature or toxicity of grain dust, the promulgated standards should not be interpreted to imply that grain dust is considered hazardous or toxic, but merely that the grain elevator industry is considered a significant source of particulate matter emissions. Studies indicate that, as a general class, particulate matter causes adverse health and welfare effects. In addition, some studies indicate that dust from grain elevators causes adverse health effects to elevator workers and that grain dust emissions are a factor contributing to an increased incidence of asthma attacks in the general population living in the vicinity of grain elevators.

EMISSION CONTROL TECHNOLOGY

A number of commenters were concerned with the reasonableness of the emission control technology which was used as the basis for the proposed standards limiting emissions from railcar unloading stations and grain dryers.

A number of commenters believed it was unreasonable to base the standards on a four-sided shed to capture emissions from railcar unloading stations at grain elevators which use unit trains. The data supporting the proposed standards were based on observations of visible emissions at a grain elevator which used this type of shed to control emissions from the unloading of railcars. This grain elevator, however, did not use unit trains. Based on information included in a number of comments, the lower rail rate for grain shipped by unit trains places a limit on the amount of time a grain elevator can hold the unit train. The additional time required to uncouple and recouple each car individually could cause a grain elevator subject to the proposed standards to exceed this time limit and thus lose the cost benefit gained by the use of unit trains. In light of this fact, the proposed visible emission limit for railcar unloading is considered unreasonable. The promulgated standards, therefore, are based upon the use of a two-sided shed for railcar unloading stations. This change in the control technology resulted in a change to the visible emission limit for railcar unloading stations and is discussed later.

A number of comments were received concerning the proposed standard for column dryers. The proposed standards would have permitted the maximum hole size in the perforated plates used in column dryers to be no larger than 2.1 mm (0.084 inch) in diameter for the dryer to automatically be in compliance with the standard. A few comments contained visible emission data taken by certified opacity observers which indicated that column dryers with perforated plates containing holes of 2.4 mm (0.094 inch) diameter could meet a 0-percent opacity emission limit. Other comments indicated that sorghum cannot be dried in column dryers with a hole size smaller than 2.4 mm (0.094 inch) diameter without plugging problems. In light of these data and information, the specification of 2.1 mm diameter holes is considered unreasonable and the promulgated standards apply only to column dryers containing perforated plates with hole sizes greater than 2.4 mm in diameter.

STRINGENCY OF THE STANDARDS

Many commenters questioned whether the standards for various affected facilities could be achieved even if the best system of emission reduction were installed, maintained, and properly operated. These commenters pointed out that a number of variables can affect the opacity of visible emissions during unloading, handling, and loading of grain and they questioned whether enough opacity observation had been taken to assure that the standards could be attained under all operating conditions. The variables mentioned most frequently were wind speed and type, dustiness, and moisture content of grain.

It is true that wind speed could have some effect on the opacity of visible emissions. A well-designed capture system should be able to compensate for this effect to a certain extent, although some dust may escape if wind speed is too high. Compliance with standards of performance, however, is determined only under conditions representative of normal operation, and judgment by State and Federal enforcement personnel will take wind conditions into account in enforcing the standards.

It is also true that the type, dustiness, and moisture content of grain affect the amount of particulate matter emissions generated during unloading, handling, and loading of grain. A well-designed capture system, however, should be designed to capture dust under adverse conditions and should, therefore, be able to compensate for these variables.

In developing the data base for the proposed standards, over 60 plant visits were made to grain terminal and storage elevators. Various grain unloading, handling, and loading operations were inspected under a wide variety of conditions. Consequently, the standards were not based on conjecture or surmise, but on observations of visible emissions by certified opacity observers at well-controlled existing grain elevators operating under routine conditions. Not all grain elevators were visited, however, and not all operations within grain elevators were inspected under all conditions. Thus, while the proposed standards were based upon a sufficiently broad data base to allow extrapolation of the data, particular attention was paid to those comments submitted during the public comment period which included visible emission data taken by certified observers from operations at grain elevators which were using the same emission control systems the proposed standards were based upon. Evaluation of these data indicates that the visible emission limit for truck unloading stations and railcar loading stations should be 5 percent opacity instead of 0 percent opacity which was proposed. The promulgated standards, therefore, limit visible emissions from these facilities to 5 percent opacity.

As discussed earlier, the emission control technology selected as the basis for the visible emissions standard for railcar unloading has been changed from a four-sided shed to a two-sided shed. Visible emission data included with the public comments indicate that emissions from a two-sided shed will not exceed 5 percent opacity. Consequently, the promulgated standards limit visible emissions from railcar unloading stations to 5 percent opacity.

A number of commenters also indicated that the opacity limit included in the proposed standards for barge loading was too stringent. One commenter indicated that the elevator operator had no control over when the "topping off" operation commenced because the ship captain and the stevedores decide when to start "topping off." Several State agencies commented that the standards should be at least 20 percent opacity. Based on these comments, the standards for barge and ship loading operations have been increased to 20 percent opacity during all loading operations. The comments indicate that this standard will still require use of the emission control technology upon which the proposed standards were based.

Data included with the public comments confirm that a visible emission limit of 0 percent opacity is appropriate for grain-handling equipment, grain dryers, and emission control equipment. Consequently, the visible emission limits for these facilities have not been changed.

OPACITY

Many commenters misunderstood the concept of opacity and how it is used to measure visible emissions. Other commenters stated that opacity measurements were not accurate below 10 to 15 percent opacity and a standard below these levels was unenforceable.

Opacity is a measure of the degree to which particulate matter or other visible emissions reduce the transmission of light and obscure the view of an object in the background. Opacity is expressed on a scale of 0 to 100 percent with a totally opaque plume assigned a value of 100 percent opacity. The concept of opacity has been used in the field of air pollution control since the turn of the century. The concept has been upheld in courts throughout the country as a reasonable and effective means of measuring visible emissions.

Opacity for purposes of determining compliance with the standard is not determined with instruments but is determined by a qualified observer following a specific procedure. Studies have demonstrated that certified observers can accurately determine the opacity of visible emissions. To become certified, an individual must be trained and must pass an examination demonstrating his ability to accurately assign opacity levels to visible emissions. To remain certified, this training must be repeated every 6 months.

In accordance with method 9, the procedure followed in making opacity determinations requires that an observer be located in a position where he has a clear view of the emission source with the sun at his back. Instantaneous opacity observations are recorded every 15 seconds for 6 minutes (24 observations). These observations are recorded in 5 percent increments (i.e., 0, 5, 10, etc.). The arithmetic average of the 24 observations, rounded off to the nearest whole number (i.e., 0.4 would be rounded off to 0), is the value of the opacity used for determining compliance with visible emission standards. Consequently, a 0 percent opacity standard does not necessarily mean there are no visible emissions. It means either that visible emissions during a 6-minute period are not sufficient to cause a certified observer to record them as 5 percent opacity, or that the average of the twenty-four 15-second observations is calculated to be less than 0.5 percent. Consequently, although emissions released into the atmosphere from an emission source may be visible to a certified observer, the source may still be found in compliance with a 0 percent opacity standard.

Similarly, a 5-percent opacity standard permits visible emissions to exceed 5 percent opacity occasionally. If, for example, a certified observer recorded the following twenty-four 15-second observations over a 6-minute period: 7 observations at 0 percent opacity; 11 observations at 5 percent opacity; 3 observations at 10 percent opacity; and 3 observations at 15 percent opacity, the average opacity would be calculated as 5.4 percent. This value would be rounded off to 5 percent opacity and the source would be in compliance with a 5 percent opacity standard.

Some of the commenters felt the proposed standards were based only on one 6-minute reading of the opacity of visible emissions at various grain elevator facilities. None of the standards were based on a single 6-minute reading of opacity. Each of the standards were based on the highest opacity readings recorded over a period of time, such as 2 or 4 hours, at a number of grain elevators.

A number of commenters also felt the visible emission standards were too stringent in light of the maximum absolute error of 7.5 percent opacity associated with a single opacity observation. The methodology used to develop and enforce visible emission standards, however, takes into account this observer error. As discussed above, visible emission standards are based on observations recorded by certified observers at well-controlled existing facilities operating under normal conditions. When feasible, such observations are made under conditions which yield the highest opacity readings such as the use of a highly contrasting background. These readings then serve as the basis for establishing the standards. By relying on the highest observations, the standards inherently reflect the highest positive error introduced by the observers.

Observer error is also taken into account in enforcement of visible emission standards. A number of observations are normally made before an enforcement action is initiated. Statistically, as the number of observations increases, the error associated with these observations taken as a group decreases. Thus, while the absolute positive error associated with a single opacity observation may be 7.5 percent, the error associated with a number of opacity observations, taken to form the basis for an enforcement action, may be considerably less than 7.5 percent.

ECONOMIC IMPACT

Several commenters felt the estimated economic impact of the proposed standards was too low. Some commenters questioned the ventilation flow rate volumes used in developing these estimates. The air evacuation flow rates and equipment costs used in estimating the costs associated with the standards, however, were based on information obtained from grain elevator operators during visits to facilities which were being operated with visible emissions meeting the proposed standards. These air evacuation flow rates and equipment costs were also checked against equipment vendor estimates and found to be in reasonable agreement. These ventilation flow rates, therefore, are compatible with the opacity standards. Thus, the unit cost estimates developed for the proposed standards are considered reasonably accurate.

Many commenters felt that the total cost required to reduce emissions to the levels necessary to comply with the visible emission standards should be assigned to the standards. The relevant costs, however, are those incremental costs required to comply with these standards above the costs required to comply with existing State or local air pollution regulations. While it is true that some States have no regulations, other States have regulations as stringent as the promulgated standards. Consequently, an estimate of the costs required to comply with the typical or average State regulation, which lies between these extremes, is subtracted from the total cost of complying with the standards to identify the cost impact directly associated with these standards.

Most State and local regulations, for example, require aspriation of truck dump pit grates and installation of cyclones to remove particulate matter from the aspirated air before release to the atmosphere. The promulgated standards would require the addition of a bifold door and the use of a fabric filter baghouse instead of a cyclone. The cost associated with the promulgated standards, therefore, is only the cost of the bifold doors and the difference in cost between a fabric filter baghouse and a cyclone.

In conclusion, the unit cost estimates developed for the proposed standards are essentially correct and generally reflect the costs associated with the promulgated standards. As a result, the economic impact of the promulgated standards on an individual grain elevator is considered to be about the same as that of the proposed standards. The maximum additional cost that would be imposed on most grain elevators subject to compliance with the promulgated standards will probably be less than a cent per bushel. The impact of these additional costs imposed on an individual grain elevator will be small.

Based on information contained in comments submitted by the National Grain and Feed Association, approximately 200 grain terminal elevators and grain storage elevators at grain processing plants will be covered by the standards over the next 5 years. Consequently, over this 5-year period the total incremental costs to control emissions at these grain elevators to comply with the promulgated standards, above the costs to control emissions at these elevators to comply with State or local air pollution control requirements, is $15 million in capital costs and $3 million in annualized costs in the 5th year. Based on this estimate of the national economic impact, the promulgated standards will have no significant effect on the supply and demand of grain or grain products, or on the growth of the domestic grain industry.

ENERGY IMPACT

A number of commenters believed that the energy impact associated with the proposed standards had been underestimated and that the true impact would be much greater. As pointed out above, the major reason for this disagreement is probably due to the fact that these commenters assigned the full impact of air pollution control to the proposed standards, whereas the impact associated with compliance with existing State and local air pollution control requirements should be subtracted. In the example discussed above concerning costs, the additonal energy requirements associated with the promulgated standards is simply the difference in energy required to operate a fabric filter baghouse compared to a cyclone.

For emission control equipment such as cyclones and fabric filter bag houses, energy consumption is directly proportional to the pressure drop across the equipment. It was assumed that the pressure drop across a cyclone required to comply with existing State and local requirements would be about 80 percent of that across a fabric filter baghouse required to comply with the promulgated standards. This is equivalent to an increase in energy consumption required to operate air pollution control equipment of about 25 percent. This represents an increase of less than 5 percent in the totl energy consumption of a grain elevator.

Assuming 200 grain elevators become subject to the promulgated standards over the next 5 years, this energy impact will increase national energy consumption by less than 1,600 m^3 (ca. 10,000 U.S. barrels) per year in 1982. This amounts to less than 2 percent of the capacity of a large marine oil tanker and is an insignificant increase in energy consumption.

MODIFICATION

Many commenters were under the mistaken impression that all existing grain elevators would have to comply with the proposed standards and that retrofit of air pollution control equipment on existing facilities within grain elevators would be required. This is not the case. The proposed standards would have applied only to new, modified, or reconstructed facilities within grain elevators. Similarly, the promulgated standards apply only to new, modified, or reconstructed facilities and not existing facilities.

Modified facilities are only subject to the standards if the modification results in increased emissions to the atmosphere from that facility. Furthermore, any alteration which is considered routine maintenance or repair is not considered a modification. Where an alteration is considered a modification, only those facilities which are modified have to comply with the standards, not the entire grain elevator. Consequently, the standards apply only to major alterations of individual facilities at existing grain elevators which result in increased emissions to the atmosphere, not to alterations which are considered routine maintenance and repair. Major alterations that do not result in increased emissions, such as alterations where existing air pollution control equipment is upgraded to maintain emissions at their previous level, are not considered modifications.

The following examples illustrate how the promulgated standards apply to a grain elevator under various circumstances. The proposed standards would have applied in the same way.

(1) If a completely new grain elevator were built, all affected facilities would be subject to the standards.

(2) If a truck unloading station at an existing grain elevator were modified by making a capital expenditure to increase unloading capacity and this resulted in increased emissions to the atmosphere in terms of pounds per hour, then only that affected facility (i. e., the modified truck unloading station) would be subject to the standards. The remaining facilities within the grain elevator would not be subject to the standards.

(3) if a grain elevator contained three grain dryers and one grain dryer were replaced with a new grain dryer, only the new grain dryer would be subject to the standards.

The initial assessment of the potential for modification of existing facilities concluded that few modifications would occur. The few modifications that were considered likely to take place would involve primarily the upgrading of existing country grain elevators into high throughput grain elevator terminals. A large number of commenters, however, indicated that they believed many modifications would occur and that many existing grain elevators would be required to comply with the standards.

To resolve this confusion and clarify the meaning of modification, a meeting was held with representatives of the grain elevator industry to identify various alterations to existing facilities that might be considered modifications. A list of alterations was developed which frequently occur within grain elevators, primarily to reduce labor costs or to increase grain handling capacity, although not necessarily annual grain throughput. The impact of considering four of these alterations as modifications, subject to compliance with the standards, was viewed as unreasonable. Consequently, they are exempted from consideration as modifications in the promulgated standards.

In particular, the four alterations within grain elevators which are specifically exempt from the promulgated standards are (1) The addition of gravity load-out spouts to existing grain storage or grain transfer bins; (2) the addition of electronic automatic grain weighing scales which increases hourly grain handling capacity; (3) the replacement of motors and drive trains driving existing grain handling equipment with larger motors and drive trains which increases hourly grain handling capacity; and (4) the addition of grain storage capacity with no increase in hourly grain handling capacity.

If the first alteration were considered a modification, this could require installation of a load-out shed thereby requiring substantial reinforcement of the grain storage or grain transfer bin to support the weight of emission control equipment. In light of the relatively small expenditure usually required to install additional gravity load-out spouts to existing grain storage or transfer bins, and the relatively large expenditure that would be required to install a load-out shed or to reinforce the storage or transfer bin, consideration of this sort of alteration within an existing grain elevator as a modification was viewed as unreasonable.

Under the general modification regulation which applies to all standards of performance, alteration two, the addition of electronic automatic grain weighing scales, would be considered a change in the method of operation of the affected facility if it were to increase the hourly grain throughput. If this alteration were to increase emissions to the atmosphere and require a capital expenditure, the grain receiving or loading station whose method of operation had changed (i.e., increased grain throughput), would be considered a modified facility subject to the standards. Consideration of this type of alteration, which would result in only minor changes to a facility, is viewed as unreasonable in light of the relatively high expenditure this could require for existing grain elevators to comply with the standards.

Alterations three and four, replacement of existing motors and drives with larger motors and drives and addition of grain storage capacity with no increase in the hourly grain handling capacity, would probably not be considered modifications under the general modification regulation. Since it is quite evident that there was considerable confusion concerning modifications, however, alterations three and four, along with alterations one and two discussed above, are specifically exempt from consideration as modifications in the promulgated standards.

The modification provisions in 40 CFR 60.14(e) exempt certain physical or operational changes from being considered as modifications, even though an increase in emission rate occurs. Under 40 CFR 60.14(e)(2), if an increase in production rate of an existing facility can be accomplished without a capital expenditure on the stationary source containing that facility, the change is not considered a modification.

A capital expenditure is defined as any amount of money exceeding the product of the Internal Revenue Service (IRS) "annual asset guideline repair allowance percentage" times the basis of the facility, as defined by section 1012 of the Internal Revenue Code. In the case of grain elevators, the IRS has not listed an annual asset guideline repair allowance percentage. Following discussions with the IRS, the Department of Agriculture, and the grain elevator industry, the Agency determined that 6.5 percent is the appropriate percentage for the grain elevator industry. If the capital expenditures required to increase the production rate of an existing facility do not exceed the amount calculated under the IRS formula, the change in the facility is not considered a modification. If the expenditures exceed the calculated amount, the change in operation is considered a modification and the facility must comply with NSPS.

Often a physical or operational change to an existing facility to increase production rate will result in an increase in the production rate of another existing facility, even though it did not undergo a physical or operational change. For example, if new electronic weighing scales were added to a truck unloading station to increase grain receipts, the production rate and emission rate would increase at the unloading station. This could result in an increase in production rate and emission rate at other existing facilities (e.g., grain handling operations) even though physical or operational changes did not occur. Under the present wording of the regulation, expenditures made throughout a grain elevator to adjust for increased production rate would have to be considered in determining if a capital expenditure had been made on each facility whose operation is altered by the production increase. If the capital expenditure made on the truck unloading station were considered to be made on each existing facility which increased its production rate, it is possible that the alterations on each such facility would qualify as modifications. Each facility would, therefore, have to meet the applicable NSPS.

Such a result is inconsistent with the intent of the regulation. The Agency intended that only capital expenditures made for the changed facility are to be considered in determining if the change is a modification. Related expenditures on other existing facilities are not to be considered in the calculation. To clarify the regulation, the phrase "the stationary source containing" is being deleted. Because this is a clarification of intent and not a change in policy, the amendment is being promulgated as a final regulation without prior proposal.

PERFORMANCE TEST

Several commenters were concerned about the costs of conducting performance tests on fabric filter baghouses. These commenters stated that the costs involved might be a very substantial portion of the costs of the fabric filter baghouse itself, and several baghouses may be installed at a moderately sized grain elevator. The commenters suggested that a fabric filter baghouse should be assumed to be in compliance without a performance test if it were properly sized. In addition, the opacity standards could be used to demonstrate compliance.

It would not be wise to waive performance tests in all cases. Section 60.8(b) already provides that a performance test may be waived if "the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard." Since performance tests are heavily weighed in court proceedings, performance test requirements must be retained to insure effective enforcement.

SAFETY CONSIDERATIONS

In December 1977, and January 1978, several grain elevators exploded. Allegations were made by various individuals within the grain elevator industry contending that Federal air pollution control regulations were contributing to an increase in the risk of dust explosions at grain elevators by requiring that building doors and windows be closed and by concentrating grain dust in emission control systems. Investigation of these allegations indicates they are false.

There were no Federal regulations specifically limiting dust emissions from grain elevators which were in effect at the time of these grain elevator explosions. A number of State and local air pollution control agencies, however, have adopted regulations which limit particulate matter emissions from grain elevators. Many of these regulations were developed by States and included in their implementation plans for attaining and maintaining the NAAQS for particulate matter. Particulate matter, as a general class, can cause adverse health effects; and the NAAQS, which were promulgated on April 30, 1971, were established at levels necessary to protect the public health and welfare.

Although compliance with State or local air pollution control regulations, or the promulgated standards of performance, can be achieved in some instances by closing building doors and windows, this is not the objective of these regulations and is not an acceptable means of compliance. The objective of State and local regulations and the promulgated standards of performance is that dust be captured at those points within grain elevators where it is generated through the use of effective hoods or enclosures with air aspiration, and removed from the grain elevator to an air pollution control device. This is the basis for the promulgated standards of performance. Compliance with air pollution control regulations and the promulgated standards of performance does not require that windows and doors in buildings be closed to prevent escape of dust and this practice may in fact be a major safety hazard.

Fabric filter baghouses have been used for many years to collect combustible dusts such as wheat flour. There have been extremely few incidences of dust explosions or fires caused by such emission control devices in the flour industry. In the grain elevator industry, no air pollution control device has been identified as the cause of a grain elevator explosion. Consequently, fabric filter baghouses, or emission control devices in general, which are properly designed, operated, and maintained will not contribute to an increased risk of dust explosions at grain elevators.

These conclusions were supported at a joint meeting between representatives of EPA; the Federal Grain Inspection Service (FGIS) of the Department of Agriculture; the Occupational Safety and Health Administration (OSHA); the grain elevator industry; and the fire insurance industry. Installation and use of properly designed, operated, and maintained air pollution control systems were found to be consistent with State and local air pollution regulations, OSHA regulations, and national fire codes. Chapter 6 of the National Fire Code for Grain Elevators and Bulk Grain Handling Facilities (NFPA No. 61-B), which was prepared by the National Fire Protection Association, for example, recommends that "dust shall be collected at all dust producing points within the processing facilities." The code then goes on to specially recommend that all elevator boots, automatic scales, scale hoppers, belt loaders, belt discharges, trippers, and discharge heads, and all machinery such as cleaners, scalpers, and similar devices be provided with enclosures or dust hoods and air aspiration.

Consequently, compliance with existing State or local air pollution regulations, or the promulgated standards of performance, will not increase the risk of dust explosions at grain elevators if the approach taken to meet these regulations is capture and control of dust at those points within an elevator where it is generated. If, however, the approach taken is merely to close doors, windows, and other openings to trap dust within the grain elevator, or the air pollution control equipment is allowed to deteriorate to the point where it is no longer effective in capturing dust as it is generated, then ambient concentrations of dust within the elevator will increase and the risk of explosion will also increase.

The House Subcommittee on Compensation, Health, and Safety is currently conducting oversight hearings to determine if something needs to be done to prevent these disastrous grain elevator explosions. The FGIS, EPA, and OSHA testified at these oversight hearings on January 24 and 25, 1978. The testimony indicated that dust should be captured and collected in emission control devices in order to reduce the incidence of dust explosions at grain elevators, protect the health of employees from such ailments as "farmer's lung," and prevent air pollution. Consequently, properly operated and maintained air pollution control equipment will not increase the risk of grain elevator explosions.

MISCELLANEOUS

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIP's) approved or promulgated under section 110 of the act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173 of the act requires, among other things, that a new or modified source constructed in an area in violation of the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source as defined in section 171(3). In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the act (part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology for all pollutants regulated under the act. The term "best available control technology" (BACT), as defined in section 169(3), means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to sections 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), statutorily, costs do not play such a role in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

ECONOMIC IMPACT ASSESSMENT

An economic assessment has been prepared as required under section 317 of the Act."

Dated: July 26, 1978.

DOUGLAS M. COSTLE,
Administrator.

REFERENCES

1. "Standards Support and Environmental Impact Statement—Volume I: Proposed Standards of Performance for Grain Elevator Industry," U.S. Environmental Protection Agency—OAQPS, EPA-450/2-77-001a, Research Triangle Park, N.C., January 1977.

2. "Draft—For Review Only: Evaluation of Public Comments: Standards of Performance For Grain Elevators," U.S. Environmental Protection Agency—OAQPS, Research Triangle Park, N.C., August 1977.

3. "Standards Support and Environmental Impact Statement—Volume II: Promulgated Standards of Performance for Grain Elevator Industry," U.S. Environmental Protection Agency—OAQPS, EPA-450/2-77-001b, Research Triangle Park, N.C., April 1978.

Part 60 of chapter I, title 40 of the Code of Federal Regulations is amended as follows:

Subpart A—General Provisions

1. Section 60.2 is amended by revising paragraph (v). The revised paragraph reads as follows:

§ 60.2 Definitions.

* * * * *

(v) "Particulate matter" means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

* * * * *

§ 60.14 [Amended]

2. Section 60.14 is amended by deleting the words "the stationary source containing" from paragraph (e)(2).

3. Part 60 is amended by adding subpart DD as follows:

Subpart DD—Standards of Performance for Grain Elevators

Sec.
60.300 Applicability and designation of affected facility.
60.301 Definitions.
60.302 Standard for particulate matter.
60.303 Test methods and procedures.
60.304 Modification.

AUTHORITY: Secs. 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart DD—Standards of Performance for Grain Elevators

§ 60.300 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility at any grain terminal elevator or any grain storage elevator, except as provided under § 60.304(b). The affected facilities are each truck unloading station, truck loading station, barge and ship unloading station, barge and ship loading station, railcar loading station, railcar unloading station, grain dryer, and all grain handling operations.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after (date of reinstatement of proposal) is subject to the requirements of this part.

§ 60.301 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the act and in subpart A of this part.

(a) "Grain" means corn, wheat, sorghum, rice, rye, oats, barley, and soybeans.

(b) "Grain elevator" means any plant or installation at which grain is unloaded, handled, cleaned, dried, stored, or loaded.

(c) "Grain terminal elevator" means any grain elevator which has a permanent storage capacity of more than 88,100 m^3 (ca. 2.5 million U.S. bushels), except those located at animal food manufacturers, pet food manufacturers, cereal manufacturers, breweries, and livestock feedlots.

(d) "Permanent storage capacity" means grain storage capacity which is inside a building, bin, or silo.

(e) "Railcar" means railroad hopper car or boxcar.

(f) "Grain storage elevator" means any grain elevator located at any wheat flour mill, wet corn mill, dry corn mill (human consumption), rice mill, or soybean oil extraction plant which has a permanent grain storage capacity of 35,200 m^3 (ca. 1 million bushels).

(g) "Process emission" means the particulate matter which is collected by a capture system.

(h) "Fugitive emission" means the particulate matter which is not collected by a capture system and is released directly into the atmosphere from an affected facility at a grain elevator.

(i) "Capture system" means the equipment such as sheds, hoods, ducts, fans, dampers, etc. used to collect particulate matter generated by an affected facility at a grain elevator.

(j) "Grain unloading station" means that portion of a grain elevator where the grain is transferred from a truck, railcar, barge, or ship to a receiving hopper.

(k) "Grain loading station" means that portion of a grain elevator where the grain is transferred from the elevator to a truck, railcar, barge, or ship.

(l) "Grain handling operations" include bucket elevators or legs (excluding legs used to unload barges or ships), scale hoppers and surge bins (garners), turn heads, scalpers, cleaners, trippers, and the headhouse and other such structures.

(m) "Column dryer" means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in one or more continuous packed columns between two perforated metal sheets.

(n) "Rack dryer" means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in a cascading flow around rows of baffles (racks).

(o) "Unloading leg" means a device which includes a bucket-type elevator which is used to remove grain from a barge or ship.

§ 60.302 Standard for particulate matter.

(a) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any gases which exhibit greater than 0 percent opacity from any:

(1) Column dryer with column plate perforation exceeding 2.4 mm diameter (ca. 0.094 inch).

(2) Rack dryer in which exhaust gases pass through a screen filter coarser than 50 mesh.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility except a grain dryer any process emission which:

(1) Contains particulate matter in excess of 0.023 g/dscm (ca. 0.01 gr/dscf).

(2) Exhibits greater than 0 percent opacity.

(c) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any fugitive emission from:

(1) Any individual truck unloading station, railcar unloading station, or railcar loading station, which exhibits greater than 5 percent opacity.

(2) Any grain handling operation which exhibits greater than 0 percent opacity.

(3) Any truck loading station which exhibits greater than 10 percent opacity.

(4) Any barge or ship loading station which exhibits greater than 20 percent opacity.

(d) The owner or operator of any barge or ship unloading station shall operate as follows:

(1) The unloading leg shall be enclosed from the top (including the receiving hopper) to the center line of the bottom pulley and ventilation to a control device shall be maintained on both sides of the leg and the grain receiving hopper.

(2) The total rate of air ventilated shall be at least 32.1 actual cubic meters per cubic meter of grain handling capacity (ca. 40 ft³/bu).

(3) Rather than meet the requirements of subparagraphs (1) and (2), of this paragraph the owner or operator may use other methods of emission control if it is demonstrated to the Administrator's satisfaction that they would reduce emissions of particulate matter to the same level or less.

§ 60.303 Test methods and procedures.

(a) Reference methods in appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with the standards prescribed under § 60.302 as follows:

(1) Method 5 or method 17 for concentration of particulate matter and associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate;

(4) Method 3 for gas analysis; and

(5) Method 9 for visible emissions.

(b) For method 5, the sampling probe and filter holder shall be operated without heaters. The sampling time for each run, using method 5 or method 17, shall be at least 60 minutes. The minimum sample volume shall be 1.7 dscm (ca. 60 dscf).

(Sec. 114, Clean Air Act, as amended (42 U.S.C. 7414).)

§ 60.304 Modifications.

(a) The factor 6.5 shall be used in place of "annual asset guidelines repair allowance percentage," to determine whether a capital expenditure as defined by § 60.2(bb) has been made to an existing facility.

(b) The following physical changes or changes in the method of operation shall not by themselves be considered a modification of any existing facility:

(1) The addition of gravity loadout spouts to existing grain storage or grain transfer bins.

(2) The installation of automatic grain weighing scales.

(3) Replacement of motor and drive units driving existing grain handling equipment.

(4) The installation of permanent storage capacity with no increase in hourly grain handling capacity.

[FR Doc. 78-21444 Filed 8-2-78; 8:45 am]

91

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 921-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to Kraft Pulp Mills Standard and Reference Method 16

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action amends the standards of performance for Kraft pulp mills by adding a provision for determining compliance of affected facilities which use a control system incorporating a process other than combustion. This amendment is necessary because the standards would place control systems other than combustion at a disadvantage. The intent of this amendment is to remove any preclusion of new and improved control systems. This action also amends Reference Method 16 to insure that the testing procedure is consistent with the promulgated standards.

EFFECTIVE DATE: August 7, 1978.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: Standards of performance for Kraft pulp mills were promulgated on February 23, 1978. On March 31, 1978, the National Council for Air and Stream Improvement (NCASI) requested two changes to these standards to prevent their interpretation in a manner which was inconsistent with their intent. The purpose of these amendments, therefore, is to clarify the intent of the standards.

OXYGEN CORRECTION FACTORS

In § 60.283(a)(1), the percent oxygen to which TRS emissions must be corrected was specified. The purpose of this specification was to provide a consistent basis for the determination of TRS emissions. Ten percent was selected because it reflected the observed oxygen concentrations on facilities controlled by the best system of emission reduction which was incineration. The NCASI pointed out, however, that the specification of a 10-percent oxygen level on sources which characteristically contain higher levels would effectively discourage the development of control technologies other than incineration.

The purpose of an emission standard is to reduce total emissions to the atmosphere. If an emission control technique should evolve which is capable of achieving the same mass rate of emissions from a given facility, use of that technique should be permitted. The standard, as written, could have inhibited the development of new technologies, if misinterpreted. Therefore, to remove this potential source of misinterpretation, § 60.283(a)(1)(v) has been added to the standard to provide for correction to untreated oxygen concentration in the case of brown stock washers, black liquor oxidation systems, or digester systems.

REFERENCE METHOD 16

The second point of concern to the NCASI was the correction factor to be applied for sampling system losses contained in the post-test procedures (paragraph 10.1) of method 16. The specific concern was the specification that a test gas be introduced at the beginning of the probe to determine sample loss in the sampling train. The data base for the promulgated standard considered only TRS losses in the sampling train, not the probe or probe filter. Consequently, the post-test procedures are amended to require the determination of sampling train losses by introducing the test gas after the probe filter consistent with the data base supporting the promulgated standards.

MISCELLANEOUS

The Administrator finds that good cause exists for omitting prior notice and public comment on these amendments and for making them immediately effective because they simply clarify the existing regulations and impose no additional substantive requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for revisions determined by the Administrator to be substantial. Since the costs associated with the proposed amendments would have a negligible impact on consumer costs, the Administrator has determined that the proposed amendments are not substantial and do not require preparation of an economic impact assessment.

Dated: August 1, 1978.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of chapter I, title 40 of the Code of Federal Regulations is amended to read as follows:

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1. In § 60.283, paragraph (a)(1) is amended to read as follows:

§ 60.283 Standard for total reduced sulfur (TRS).

* * * * *

(a) * * *

(1) * * *

(v) The gases from the digester system, brown stock washer system, condensate stripper system, or black liquor oxidation system are controlled by a means other than combustion. In this case, these systems shall not discharge any gases to the atmosphere which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to the actual oxygen content of the untreated gas stream.

* * * * *

2. In appendix A, paragraph 10.1 of method 16 is amended to read as follows:

* * * * *

10. POST-TEST PROCEDURES

10.1 Sample line loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ± 20 percent, must be introduced into the sampling system in sufficient quantities to insure that there is an excess of sample which must be vented to the atmosphere. The sample must be introduced immediately after the probe and filter and transported through the remainder of the sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss.

For sampling losses greater than 20 percent in a sample run, the sample run is not to be used when determining the arithmetic mean of the performance test. For sampling losses of 0-20 percent, the sample concentration must be corrected by dividing the sample concentration by the fraction of recovery. The fraction of recovery is equal to one minus the ratio of the measured concentration to the known concentration of hydrogen sulfide in the sample line loss procedure. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.

* * * * *

(Sec. 111, 301(a)), Clean Air Act as amended (42 U.S.C. 7411, 7601(a)).)

[FR Doc. 78-21801 Filed 8-4-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 152

MONDAY, AUGUST 7, 1978

92

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY.

SUBCHAPTER C—AIR PROGRAMS

[FRL 987-8]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority for State of Rhode Island

AGENCY: Environmental Protection Agency (EPA).

ACTION: Amendment.

SUMMARY: The delegation of authority to the State of Rhode Island for the standards of performance for new stationary sources (NSPS) was made on March 31, 1978. This amendment which adds the address of the Rhode Island Department of Environmenal Managment, reflects this delegation. A notice announcing this delegation is published today in the FEDERAL REGISTER.

EFFECTIVE DATE: October 16, 1978.

FOR FURTHER INFORMATION CONTACT:

John Courcier, Air Branch, EPA Region I, Room 2113, JFK Federal Building, Boston, Mass. 02203, 617-223-4448.

SUPPLEMENTARY INFORMATION: Under the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of Rhode Island on March 31, 1978, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A notice announcing this delegation is published today elsewhere in this (43 part of the FEDERAL REGISTER. The amended § 60.4, which adds the address of the Rhode Island Department of Environmental Management to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on March 31, 1978, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended, 42 U.S.C. 7412.

Dated: September 18, 1978.

WILLIAM R. ADAMS, Jr.,
Regional Administrator,
Region I.

Part 60 of chapter I, title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by adding subparagraph (OO) to read as follows:

§ 60.4 Address

* * * * *

(b) * * *

(OO) State of Rhode Island, Department of Environmental Management, 83 Park Street, Providence, R.I. 02908

[FR Doc. 78-29105 Filed 10-13-78; 8:49 am]

FEDERAL REGISTER, VOL. 43, NO. 200

MONDAY, OCTOBER 16, 1978

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Parts 51, 52, 53, 58, 60]

[FRL 907-1]

AIR QUALITY SURVEILLANCE AND DATA REPORTING

Proposed Regulatory Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This notice proposes to revise the requirements for ambient air quality monitoring for purposes of the State implementation plans (SIP's) and for reporting air quality data to EPA as required by section 110(a)(2)(C) of the Clean Air Act (act). The new regulations would be in a new part 58 entitled, "Ambient Air Quality Surveillance." This new part would contain the requirements and criteria concerned with ambient air monitoring. Also included in the new part 58 would be provisions which would address other requirements of the act including provisions for monitoring criteria and air quality index reporting as required by section 319, "Air Quality Monitoring"; provisions for data reporting which would enable EPA to satisfy the requirements of section 313, "Additional Reports to Congress"; and provisions for public notification of information related to air quality standards violations which would satisfy the requirements of section 127, "Public Notification."

* * * * *

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

EPA proposes to amend part 60 of Title 40, Code of Federal Regulations, as follows:

Section 60.25, paragraph (e), is amended by changing the reference to a semiannual report required by § 51.7 to an annual report required by § 51.321. As amended, § 60.25 reads as follows:

§ 60.25 Emission inventories, source surveillance, reports.

* * * * *

(e) The State shall submit reports on progress in plan enforcement to the Administrator on an annual (calendar year) basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. Information required under this paragraph must be included in the annual report required by § 51.321 of part 51 of this chapter.

FEDERAL REGISTER, VOL. 43, NO. 152—MONDAY, AUGUST 7, 1978

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 933-3]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rule and Notice of Public Hearing.

SUMMARY: This action contains EPA's proposed list of major source categories for which standards of performance must be promulgated by August 1982. The Clean Air Act Amendments of 1977 require EPA to publish by August 1978, a list of the categories of major stationary sources which have not been previously listed as source categories for which standards of perforamce will be established. The intent of this action is to provide interested parties an opportunity to comment on the proposed list.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed list.

Comments. Comments must be received on or before October 30, 1978.

Public Hearing. The public hearing will be held on Friday, September 29, 1978.

Request to Speak at Hearing. Persons wishing to attend the hearing or present oral testimony should contact EPA by September 25, 1978.

Comments. Comments should be submitted to Gary D. McCutchen, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711.

Public Hearing. The public hearing will be held Friday, September 29, 1978, at 9 a.m. to 4 p.m., in room 3906, Waterside Mall, 401 M Street SW., Washington, D.C. Persons wishing to present oral testimony should notify Mary Jane Clark, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number 919-541-5271.

Background Document. The background document for the proposed priority list may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711, telephone number 919-541-2777. Please refer to "priorities for New Source Performance Standards Under the Clean Air Act Amendments of 1977 (EPA-450/3-78-019)."

Docket. EPA has determined that a docket is not required for this action, but public comments received and a copy of the background report used in

FEDERAL REGISTER, VOL. 43, NO. 170—THURSDAY, AUGUST 31, 1978

the development of this list will be available for public inspection and copying at the Public Information Reference Unit, Room 2922, 401 M Street SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT:

Mr. Gary McCutchen, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number 919-541-5421.

SUPPLEMENTARY INFORMATION: The new source performance standard (NSPS) program began in December 1970, when the Clean Air Act was signed into law. Authorized under section 111 of the act, NSPS were to require the best control system (considering cost) for new facilities, and were intended to complement the other air quality management approaches authorized by the 1970 act. A total of 28 source categories are regulated by NSPS, with NSPS for an additional 25 source categories under development.

During the 1977 hearings on the Clean Air Act, Congress received testimony on the need for more rapid development of NSPS. There was concern that not all sources which had the potential to endanger public health or welfare were controlled by NSPS and that the potential existed for "environmental blackmail" from source categories not subject to NSPS. This concern was explicitly expressed by the Governor of New Jersey, who felt that industry could threaten to leave, or simply not locate in, States with more stringent regulations than their neighbors. These concerns were reflected in the Clean Air Act Amendments of 1977, Specifically in section 111(f).

Section 111(f) requires that EPA publish a list of major stationary sources of air pollution not already listed under section 111(b)(1)(A); that is, for which NSPS have not yet been proposed or promulgated. The list is to be promulgated by August 7, 1978, after EPA has provided notice of and opportunity for public hearings and consulted with Governors and State air pollution control agencies. In developing priorities, EPA is to consider: (1) The quantity of emissions from each source category, (2) the extent to which each pollutant endangers public health or welfare, and (3) the mobility and competitive nature of each stationary source category, e.g., the capability of a new or existing source to locate in areas with less stringent air pollution control regulations. After the list is promulgated, Governors may submit applications under section 111(g) to add major source categories to the list, add any source category to the list which may endanger public health or welfare, change the priority ranking, or revise promulgated NSPS.

DEVELOPING THE LIST

EPA initiated development of this list by compiling information on a large number of source categories from a number of literature resources. This preliminary list was evaluated using the criteria specified in section 111(f). A draft report describing this analysis was reviewed by the National Air Pollution Control Techniques Advisory Committee on April 6, 1978. A final report is now available which, in addition to describing the methodology used to apply the criteria, provides the resource material used in developing the list.

The background report may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711 (specify "Priorities for NSPS Under the Clean Air Act Amendments of 1977," EPA-450/3-78-019).

The data were first analyzed to determine those sources which have the potential to emit 100 tons or more per year of any one pollutant. These major source categories were then subjected to a priority ranking procedure using the three criteria specified in the act. In summary, this procedure, which is described in more detail in the following section, first ranks source categories on a pollutant by pollutant basis. This results in nine lists [one for each pollutant—hydrocarbons (HC), nitrogen oxides (NO_x), particulate matter (PM), sulfur dioxide (SO_2), carbon monoxide (CO), lead (Pb), fluorides (F), acid mist (AM), and hydrogen sulfide (H_2S)] with each list ranked using the criteria in the act. In this ranking, first priority is given to quantity of emissions, second priority to potential impact on health and welfare, and third priority to mobility. Thus, sources with the greatest growth rates and emission reduction potential are high on each list; sources with limited choice of location, low growth and small emission potential are low on each list.

The nine lists are combined into one by selecting pollutant goals—a procedure which, in effect, assigns a relative priority to pollutants based upon the potential impact of NSPS. After the pollutant goals are selected, the final priority list is established through the selection of source categories which will have maximum impact on attaining the selected goals. The effect of this procedure is to emphasize control of organic (hydrocarbon), particulate matter, and NO_x emissions and to give carbon monoxide and noncriteria pollutants a lower priority.

The ranking of source categories on the list and, in fact, the differentiation between major and minor sources is sensitive to the accuracy of the data utilized. The ranking is especially sensitive to emission factors, source sizes, and source category growth rates. Because the data base used to establish the priority list was obtained from a number of literature sources and because time was not available to perform an independent verification of these data, it is expected that further study will identify certain inaccuracies in the original data base. If such errors are identified after promulgation, EPA may, as described below, take action to reorder priorities, delete sources from the list, or add sources to that list.

In developing standards for source categories on the list, EPA's first activity will be a screening study. This activity takes approximately 2 months to complete for each source category and involves gathering basic data concerning the industry for which a standard is planned. This information is obtained from State and local agencies and from owners and operators of sources in the affected industry, and is more accurate and representative than the data base used in developing the priority list. EPA expects to initiate the screening studies for all source categories listed within 18 to 24 months after promulgation of the list and, therefore, even very large errors in the priority ranking will have little effect on the date a project is started. If the screening study indicates that an NSPS would have little or no effect on emissions, or that an NSPS would be impractical, a source category can be removed from the list at the completion of the screening study before a standard is developed. Finding that uncontrolled emission rates are below 100 tons per year or that the source category exhibits a low growth rate are examples of cases which could cause EPA to remove a category or lower its priority. EPA may, however, develop standards for sources which emit less than 100 tons per year, especially certain minor sources which, in aggregate, represent a large quantity of emissions.

The proposed list identifies major source categories, defined as categories which have average size sources with the potential (uncontrolled) to emit 100 tons per year (TPY) or more of any pollutant regulated under the act. Certain new sources of smaller than average size within these categories may have less than a 100 ton per year emission potential, just as very large units from nonlisted minor source categories may have more than this potential. Thus, this list of major source categories was developed only for the purpose of defining NSPS priorities and should not be used to define sources subject to new source review (NSR), which is conducted on a case-by-case basis. Moreover, some NSR programs such as prevention of significant deterioration have separate and distinct criteria for defining a major source (e.g., 100 tons per year potential for certain source types and 250 tons per year for others).

Two groups of sources in addition to minor sources are not included on the proposed list. One group includes sources which could not be evaluated due to insufficient data. This lack of data suggests that these sources, which are identified in the background report, "Priorities for NSPS under the Clean Air Act of 1977," have not previously been regulated or studied and, therefore, are probably not major sources. Nevertheless, EPA will continue to investigate these sources and will add to the list any which are identified as being major.

The second group of unlisted source categories consists of those already listed under section 111(b)(1)(A). These are:

Fossil-fuel-fired steam generators.
Incinerators.
Protland cement plants.
Nitric acid plants.
Sulfuric acid plants.
Asphalt concrete plants.
Petroleum refineries.
Storage vessels for petroleum liquids.
Secondary lead smelters.
Secondary brass and bronze ingot production plants.
Iron and steel plants.
Sewage treatment plants.
Primary copper smelters.
Primary zinc smelters.
Primary lead smelters.
Primary aluminum reduction plants.
Phosphate fertilizer industry: Wet process phosphoric acid plants.
Phosphate fertilizer industry: Superphosphoric acid plants.
Phosphate fertilizer industry: Diammonium phosphate plants.
Phosphate fertilizer industry: Triple superphosphate plants.
Phosphate fertilizer industry: Granular triple superphosphate storage facilities.
Coal preparation plants.
Ferroalloy production facilities.
Steel plants: Electric arc furnaces.
Kraft pulpmills.
Lime plants.
Grain elevators.
Stationary gas turbines.

There are, however, some facilities (or subcategories) within these source categories for which NSPS have not been developed, but which may by themselves be significant sources of air pollution. A number of these facilities were evaluated as if they were separate source categories; three which ranked high in priority are included on the priority list to indicate that EPA plans to develop standards for them: Petroleum refinery fugitive emissions, industrial fossil-fuel-fired steam generators, and industrial-commercial incinerators. In addition to these, EPA will continue to evaluate affected facilities within listed source categories and may from time to time add these to the list. Sintering plants in the iron and steel industry is an example of a facility now being studied. Although the growth rate for new sintering capacity is presently very low, giving this facility a very low priority, EPA is continuing to assess emission control and measurement technology with a view toward possible development of a standard for sintering plants at a later date.

DETERMINING PRIORITIES

The methodology used to establish priorities is explained in detail in the report "Priorities for New Source Performance Standards Under the Clean Air Act Amendments of 1977." The description that follows conveys the basic concepts used, but does not detail the entire procedure.

The first task in the ranking procedure was to develop a method for applying the three criteria specified by the CAA amendments to each of the nine pollutants. The second task was to establish goals for each pollutant so that a single multipollutant priority list could be compiled.

The first CAA criterion, quantity of emissions, is represented by the emissions an NSPS would prevent after being in effect for a specified period of time; in this case, 10 years. Emissions for 1990 are first calculated assuming that the present level of control continues to be applied to new sources; the resulting 1990 emission level is termed T_s. Then 1990 emissions are calculated assuming a best level of control, representative of an NSPS, is applied to all new sources constructed between 1980 and 1990; this 1990 emission level is termed T_N. The emissions that could be prevented by an NSPS after 10 years is represented by the difference between T_s and T_N. The value of (T_s-T_N) represents the first CAA criterion.

The approach used to derive an objective measure of the impact or extent to which public health or welfare could be endangered consists of first determining the ambient air concentration (X) for each pollutant in the vicinity of a typical facility. This involves several assumptions, including the tape of meteorology and dispersion equations, concentration and quantity of emissions, and average stack heights and stack gas emission flow rates and temperatures. Since one pollutant could have no discernible effects at a concentration at which another pollutant could be dangerous, a method was needed to relate each of these ambient air concentrations to their health or welfare effects. The approach selected was to divide each ambient air concentration by an appropriate ambient threshold value (ATV) for that pollutant. The ATV represents a level at which public health or welfare may be endangered. The ATV is represented by the national ambient air quality standard (NAAQS) for criteria pollutants and by a concentration based on the threshold limit value for the other pollutants studied. These "normalized" values range from 0.0001 to 176 and are used to represent health or welfare endangerment. A normalized value of 1.0 would mean that ambient concentrations in the vicinity of a typical facility are approximately equal to the ATV level.

Evaluation of the mobility and competitive nature of source categories was subjective. "Mobility and competitive nature" in this analysis refers to the feasibility of stationary source categories to relocate to, or locate new facilities in, areas with less stringent air pollution control regulations. Nonmovable stationary source categories were identified on the basis of being tied either to the market (e.g., dry cleaners) or to a supply of materials (e.g., mining operations). All other stationary source categories were considered movable by default.

For each pollutant, source categories were first separated into three groups: high, medium, and low emmissions prevention potential (T_s-T_N). Each of these three emissions groups was then divided into three subgroups: high, medium, and low ambient air impact (X/ATV). Each of these subgroups was then split into two subdivisions: movable and nonmovable. Finally, within each of the 18 resulting subdivisions, source categories were ranked in order of emission prevention potential (T_s-T_N), from highest to lowest. Priority was given to high (T_s-T_N), high X/ATV, and movability, so that a prioritized listing of these subdivisions is as follows, with highest priority first:

(1) High (T_s-T_N), high X/ATV, movable.
(2) High (T_s-T_N), high X/ATV, nonmovable.
(3) High (T_s-T_N), medium X/ATV, movable.
(4) High (T_s-T_N), medium X/ATV, nonmovable.
(5) High (T_s-T_N), low X/ATV, movable.
(6) High (T_s-T_N), low X/ATV, nonmovable.
(7) Medium (T_s-T_N), high X/ATV, movable.
(8) Medium (T_s-T_N), high X/ATV, nonmovable.
(9) Medium (T_s-T_N), medium X/ATV, movable.
(10) Medium (T_s-T_N), medium X/ATV, nonmovable.
(11) Medium (T_s-T_N), low X/ATV, movable.
(12) Medium (T_s-T_N), low X/ATV, nonmovable.
(13) Low (T_s-T_N), high X/ATV, movable.
(14) Low (T_s-T_N), high X/ATV, nonmovable.

(15) Low (T_S-T_N), medium X/ATV, movable.

(16) Low (T_S-T_N), medium X/ATV, nonmovable.

(17) Low (T_S-T_N), low X/ATV, movable.

(18) Low (T_S-T_N), low X/ATV, nonmovable.

This provides a separate priority ranking for each pollutant. Developing a combined multipollutant priority list requires the selection of pollutant goals.

A computer program was written to calculate 1990 emissions from each source/pollutant combination, then determine which 1990 pollutant estimate was furthest from its goal. This became the priority pollutant, and the top priority source category from that pollutant list was selected and an NSPS (E_N level of emissions) assumed for new sources in that category from that time on. It was assumed that NSPS were promulgated at the same time for any other pollutants emitted from that source category. The computer program then recalculates 1990 emissions, selects the new priority pollutant, and repeats the selection procedure. A standard-setting rate was assumed that, beginning in 1980, results in the promulgation by the end of 1982 of NSPS for all the source categories listed. The resulting list can be found in the background report (Table 3-12, p. 113), and is the basis for the listing of major source categories that appears in this notice.

The goals for PM, SO_2, NO_x, HC, and Pb were determined by assuming all NSPS are promulgated in 1980 and then calculating 1990 emissions based on NSPS control of all new sources during that 10-year period. For SO_2 and NO_x, emissions will still increase, but for PM, HC, and Pb, 1990 emissions would be lower than 1980 emissions despite growth. Although EPA cannot set all NSPS in 1980, the emission changes that result from such an assumption provide reasonable goals to aim for.

These goals are summarized below:

Pollutant	1990 emission without NSPS,* percent change from 1980 emissions	1990 goal percent change from 1980 emissions**
Particulate matter (PM)....	+30	−5
Sulfur dioxide (SO_2).................	+20	+10
Nitrogen oxides (NO_x).................	+55	+20
Hydrocarbons (HC).................	+70	−30
Lead (Pb)............	+55	−20

*Does not take into account emission reductions that will accrue from State Implementation Plan revisions or New Source Review decisions (including prevention of significant deterioration and emission offsets).

**Determined by assuming that all NSPS are effective in 1980 and apply to all new sources constructed during the 10-year period 1980-90.

For the other pollutants (CO, AM, H_2S, and F), 1990 emissions would be lower than 1980 emissions if all NSPS were set in 1980, but these reductions are of lower priority than those listed in the preceding paragraph. The lower priority is based on prior EPA policy. AM, H_2S, and F are not regulated by National Ambient Air Quality Standards (NAAQS), and are considered lower priority than NAAQS or criteria pollutants. Although CO is a criteria pollutant, CO from stationary sources has not been considered a priority concern; emphasis has instead been on emissions from vehicles. Therefore, a 1990 goal of no increase over 1980 emissions was selected, which in effect deemphasizes CO, AM, H_2S, and F.

The goals calculated for these pollutants, based on the change in emission levels between 1980 and 1990, are shown below:

Pollutant	1990 emissions without NSPS,* percent change from 1980 emissions	1990 goal, percent change from 1980 emissions
Carbon monoxide (CO)................	+30	**0
Acid mist (AM)..	+135	**0
Hydrogen sulfide (H_2S)...	+30	**0
Fluorides (F)......	+35	**0

*Does not take into account emission reductions that will accrue from State implementation plan revisions or new source review decisions (including prevention of significant deterioration and emission offsets).

**Setting a goal of 0 percent change has the effect of deemphasizing these pollutants since reductions below 1980 emission levels are possible.

At the beginning of the computer program, the priority pollutant is determined by the difference in tons of emissions per year between the first column (projected 1990 emissions) and the second column (the 1990 emissions goal).

IDENTIFICATION OF SOURCE CATEGORIES

There are some differences between the list in the background report (table 3-12) and the list which appears below. These differences are primarily a result of aggregation of subcategories which had been subdivided for size classification and priority ranking analysis. Nonmetallic mineral mining, for example, is composed of nine subcategories, eight of which were analyzed separately (stone, sand and gravel, clay, gypsum, lime, borax, fluorspar, and phosphate rock mining) and one of which is considered a minor source (mica mining). EPA plans to study the entire non-metallic mining industry at one time, since many of the processes and control techniques are similar. For this reason, the industry is identified by a single listing. This does not necessarily imply that a single standard would apply to all sources within the listed category. Rather, as described below in the case of synthetic organic chemical manufacturing, the nature and scope of standards will be determined only after a detailed study of sources within the category.

Also, in addition to the major sources, three source categories not identified as being major source categories have been added to the list—organic solvent degreasing, industrial surface coating: metal furniture, and lead acid battery manufacture.

Organic solvent degreasing was chosen for study because this source category accounts for some 5 percent of stationary source emissions in a typical air quality control region. Thus, although individual facilities typically emit less than 100 TPY, this is a significant source of organic emissions and EPA considers it prudent to continue the development of a standard for this source category.

The metal furniture coating industry is also a significant source of organic emissions, and there are over 300 existing facilities with the potential to emit more than 100 TPY. For this reason, EPA has placed this source category on the list.

Lead acid battery manufacture is a significant source of lead emissions. An NSPS for this source category is expected to assist in attainment of the proposed National Ambient Air Quality Standard for lead.

EPA initiated work to develop standards for each of these source categories prior to the 1977 amendments to the CAA and plans to continue work on them. Interrupting work on these categories is not considered justified, as this would require that a significant amount of work be repeated.

One listed source category which deserves special attention is the synthetic organic chemical manufacturing industry (SOCMI). Preliminary estimates indicate that there may be over 600 different processes included in this source category, but only 27 of these processes have been evaluated and priority-ranked. For the other 575, there was not enough information available. As is the case with several other aggregate source categories, EPA expects to use generic standards to cover as many of the 600 processes as possible, so separate NSPS for each process are unlikely. Based on an effort which has been underway within EPA for 2 years to study this complex source category, the generic standards could regulate nearly all emissions by covering four broad areas: process facilities; storage facilities; leakage; and transport and handling losses. Also, since a number of the pollutants emitted are potentially toxic or carcinogenic, regulation under section 112, national emission standards for hazardous air pollutants

(NESHAP) rather than NSPS may be more appropriate. Therefore, SOCMI is listed as a single source category. The 27 processes evaluated are considered the most likely candidates for NSPS or NESHAP coverage through generic standards, and are listed below:

Acrylonitrile Plants.
Acetic Acid Plants.
Acrylic Acid.
Acetic Anhydride Plants.
Cyclohexane Plants.
Cyclohexanol/Cyclohexanone Plants.
Dimethyl Terephthalate Plants.
Ethylene Dichloride Plants.
Ethylene Oxide Plants.
Ethylbenzene Plants.
Ethylene Plants.
Ethylene Glycol Plants.
Formaldehyde Plants.
Maleic Anhydride Plants.
Methanol Plants.
Methyl Methacrylate Plants.
Phenol Plants.
Propylene Oxide Plants.
Terephthalic Acid Plants.
Vinyl Acetate Plants.
Phthalic Anhydride (PAN) Plants.
Acetone Plants.
Carbon Tetrachloride Plants.
Adipic Acid Plants.
Methyl Chloroform Plants.
Styrene Plants.
Allyl Chloride Plants.

Additional information has resulted in the exclusion from the list of some source categories which are shown in the background report. Mixed fuel boilers and feed and grain milling are regulated by the NSPS for fossil-fuel steam generators and grain elevators, respectively. Beer manufacture has a much lower emission level than had been assumed in the background report, and whiskey manufacture was deleted due to a lack of any demonstrated control technology.

PUBLIC PARTICIPATION

The CAA requires that EPA, prior to promulgating this list of source categories, consult with Governors and State air pollution control agencies. An invitation was extended on February 28, 1978, to the State and Territorial Air Pollution Program Administrators (STAPPA) and the National Governors' Association (NGA) to attend the first Working Group meeting, March 16, 1978, and review the draft background report and the methods used to apply the criteria. On March 24, 1978, EPA notified each Governor and the director of each State air pollution control agency by letter of this project, inviting them to participate and/or comment:

(1) At the April 5-6, 1978, National Air Pollution Control Techniques Advisory Committee NAPCTAC) meeting in Alexandria, Va.;

(2) When the final background report was mailed to them;

(3) When the list is proposed in the FEDERAL REGISTER; or

(4) At a public hearing to be held on the proposed list.

The draft background report was mailed to all NAPCTAC members, five of which represent State or local agencies, two of which represent environmental groups, and eight of which represent industry. Copies were mailed to six environmental groups and three consumer groups at the same time, and to a representative of the NGA.

Copies of the final report were sent to the Governors, State, and local air pollution control agencies, NAPCTAC members, environmental groups, the NGA, and other requesters in early July.

A public hearing will be held to discuss the proposed priority list in accordance with section 111(g)(8) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address above. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statements should be addressed to Mr. Gary D. McCutchen at the address above.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours in Washington, D.C., at the U.S. Environmental Protection Agency's Public Information Reference Unit (address same as above).

Note that application for revision of the list at any time by a Governor is specifically permitted in section 111(g). EPA must evaluate an application within 90 days, explain why an application is not accepted, and implement acceptable applications following a public hearing on the proposed action. Applications relating to NSPS may be to (1) add a major source category to the list, (2) add a source category to the list, whether major or minor, if it has the potential to endanger health or welfare, (3) revise priorities if the criteria specified in the Act have not been properly applied, or (4) revise a promulgated NSPS that no longer reflects best control technology.

DEVELOPMENT OF STANDARDS

When the list of source categories is promulgated in the FEDERAL REGISTER, EPA will undertake a program to promulgate standards for those source categories by August 7, 1982. EPA has already initiated the development of standards for nearly half of the source categories listed; work on the remaining source categories will be initiated within the next 2 years.

It should be pointed out that several of the source categories listed could be subject to standards which may be adopted under section 112 of the Clean Air Act (national emission standards for hazardous air pollutants or NESHAP). Included are byproduct coke ovens and several source categories within the petroleum transport and marketing industry. If standards are developed under section 112 for these or any other source categories on the list being proposed today, then standards would not be developed for those source categories under section 111.

The priority ranking is indicated by the number to the left of each source category and will be used to decide the order in which new projects are initiated, although this is not necessarily an indication of the order in which projects will be completed. In fact, higher priority source categories often present difficult technical and regulatory problems, and may be among the later source categories for which standards are promulgated.

It should be noted also that the source categories identified on this proposed list are not subject to the provisions of section 111(b)(1)(B) which would require proposal 120 days after adoption of the list. Rather, the promulgation of standards for sources contained on the list being proposed here will be undertaken in accordance with the time schedule prescribed in section 111(f)(1) of the Clean Air Act amendments. That is, 25 percent are to be promulgated by August 1980, 75 percent by August 1981, and all of the standards by August 1982.

Dated: August 24, 1978.

DOUGLAS M. COSTLE,
Administrator.

It is proposed to amend Part 60 of Chapter I of Title 40 of the Code of Federal Regulations by adding § 60.16 to Subpart A as follows:

§ 60.16 Priority List.

Priority
number [1]

STATIONARY FUEL COMBUSTION

16. Fossil-fuel-fired steam generators: Industrial boilers.
14. Stationary internal combustion engines.

METALLURGICAL PROCESSES

10. By-product coke ovens.
23. Foundries: Grey iron.
41. Foundries: Steel.
42. Secondary aluminum.
20. Secondary copper.
66. Secondary zinc.
67. Uranium refining.

MINERAL PRODUCTS

57. Asphalt roofing.

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[1] Low numbers have highest priority; e.g., No. 1 is high priority, No. 72 is low priority.

49. Brick and related clay products.
60. Castable refractories.
58. Ceramic clay.
48. Fiberglass.
38. Glass.
45. Gypsum.
19. Metallic mineral processing.
13. Mineral wool.
18. Non-metallic mineral processing.
64. Perlite.
21. Phosphate rock preparation.
43. Sintering: Clay and flyash.

POLYMERS AND RESINS

54. Polymers and resins: ABS-SAN resins.
12. Polymers and resins: Acrylic resins.
50. Polymers and resins: Phenolic resins.
62. Polymers and resins: Polyester resins.
30. Polymers and resins: Polyethylene.
55. Polymers and resins: Polypropylene.
53. Polymers and resins: Polystyrene.
51. Polymers and resins: Urea-melamine resins.

FOOD AND AGRICULTURAL

68. Alfalfa dehydrating.
44. Ammonium sulfate.
59. Ammonium nitrate fertilizer.
69. Animal feed defluorination.
63. Starch.
70. Urea (for fertilizer and polymers).
27. Vegetable oil.

WASTE INCINERATION

11. Incineration: Industrial-commercial.

BASIC CHEMICAL MANUFACTURE

1. Synthetic Organic Chemical Manufacturing.
61. Borax and boric acid.
47. Hydrofluoric acid.
65. Phosphoric acid: Thermal process.
40. Potash.
46. Sodium carbonate.

CHEMICAL PRODUCTS MANUFACTURE

52. Ammonia.
2. Carbon black.
31. Charcoal.
71. Detergent.
17. Explosives.
7. Fuel conversion.
34. Printing ink.
35. Synthetic fibers.
28. Synthetic rubber.
29. Varnish.

EVAPORATIVE LOSS SOURCES

6. Dry cleaning.
9. Graphic arts.
15. Industrial surface coating: Automobiles.
3. Industrial surface coating: Cans.
8. Industrial surface coating: Fabric.
37. Industrial surface coating: Large appliances.
32. Industrial surface coating: Metal coil.
5. Industrial surface coating: Paper.

PETROLEUM INDUSTRY

25. Crude oil and natural gas production.
72. Gasoline additives.
4. Petroleun. refinery: Fugitive sources.
33. Transportation and marketing.

WOOD PROCESSING

24. Chemical wood pulping: Acid sulfite.
22. Chemical wood pulping: Neutral sulfite (NSSC).
36. Plywood manufacture.

CONSUMER PRODUCTS

56. Textile processing.

MINOR SOURCE CATEGORIES

Lead acid battery manufacture. [1]
Solvent metal cleaning (degreasing). [1]
Industrial surface coating: metal furniture. [1]

AUTHORITY: Section 111 and 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601).

[FR Doc. 78-24441 Filed 8-30-78; 8:45 am]

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[1] Not prioritized, but included on list. See explanation in preamble.

ENVIRONMENTAL PROTECTION AGENCY

■

ELECTRIC UTILITY STEAM GENERATING UNITS

Proposed Standards of Performance and Announcement of Public Hearing on Proposed Standards

SUBPART Da

V-D-1

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 967-1]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The proposed standards of performance would limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified, and reconstructed electric utility steam generating units capable of combusting more than 73 megawatts (MW) heat input (250 million Btu/hour) of fossil fuel. A new reference method for determining continuous compliance with SO_2 and NO_x standards is also proposed. The Clean Air Act Amendments of 1977 require EPA to revise the current standards of performance for fossil fuel-fired stationary sources. The intended effect of this proposal is to require new, modified, and reconstructed electric utility steam generating units to use the best demonstrated systems of continuous emission reduction and to satisfy the requirements of the Clean Air Act Amendments of 1977.

The principal issue associated with this proposal is whether electric utility steam generating units firing low-sulfur-content coal should be required to achieve the same percentage reduction in potential SO_2 emissions as those burning higher sulfur content coal. Resolving this question of full versus partial control is difficult because of the significant environmental, energy, and economic implications associated with each alternative. The Administrator has not made a decision on which of the alternatives should be adopted in the final standard and solicits additional data on these impacts before promulgating the final regulation.

The conference report for the Clean Air Act Amendments of 1977 says in pertinent part:

> * * * in establishing a national percent reduction for new fossil fuel-fired sources, the conferees agreed that the Administrator may, in his discretion, set a range of pollutant reduction that reflects varying fuel characteristics. Any departure from the uniform national percentage reduction requirement, however, must be accompanied by a finding that such a departure does not undermine the basic purposes of the House provision and other provisions of the act, such as maximizing the use of locally available fuels.

This proposal sets forth the full, or uniform control alternative and sets forth other alternatives for comment as well. It should be noted that the Clean Air Act provides that new source performance standards apply from the date they are proposed and it would be easier for powerplants that start construction during the proposal period to scale down to partial control than to scale up to full control should the final standard differ from the proposal.

The final decision on the appropriate level of control will be made only after analyses are completed and public comments evaluated. Because the decision will require a careful balancing of environmental, energy, and economic impacts, the Administrator believes that extensive public involvement is essential. Comments on the factual basis for the standards and suggestions on the interpretation of data are actively solicited.

DATES: *Comments.* Comments must be received on or before November 20, 1978.

Public hearing. A separate notice is published in today's FEDERAL REGISTER announcing the time and place of a public hearing on the proposed standards.

ADDRESSES: *Comments.* Comments should be submitted to Jack R. Farmer, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711.

Background information. The background information documents (refer to section on studies) for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park N.C. 27711, telephone 919-541-2777. In addition, a copy is available for inspection in the Office of Public Affairs in each Regional Office, and in EPA's Central Docket Section in Washington, D.C.

Docket. Docket No. OAQPS-78-1, containing all supporting information used by EPA in developing the proposed standards, is available for public inspection and copying between 8 a.m. and 4 p.m., Monday through Friday, at EPA's Central Docket Section, room 2903B, Waterside Mall, 401 M Street SW., Washington, D.C. 20460.

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of this proposed rulemaking. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the promulgated rule and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review (section 307(d)(a)).

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: Summary of proposed standards; rationale; background; applicability; SO_2 standards; particulate matter standards; NO_x standards; studies; performance testing; and miscellaneous.

SUMMARY OF PROPOSED STANDARDS

APPLICABILITY

The proposed standards would apply to electric utility steam generating units that are capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel and for which construction is commenced after September 18, 1978.

SO_2 EMISSIONS

The proposed SO_2 standards would limit SO_2 emissions to 520 ng/J (1.2 lb/million Btu) heat input for solid fuel (except for 3 days per month) and 340 ng/J (0.80 lb/million Btu) for liquid and gaseous fuel (except for 3 days per month). Also, uncontrolled SO_2 emissions from solid, liquid, and gaseous fuel would be required to be reduced by 85 percent. Compliance with the SO_2 emission limitation and percent reduction would be determined on a 24-hour daily basis. The 85-percent requirement would apply at all times except for 3 days per month, when only a 75-percent SO_2 reduction requirement would apply. The percent reduction requirement would not apply if SO_2 emissions into the atmosphere are less than 86 ng/J (0.20 lb/million Btu) heat input.

The percent reduction would be computed on the basis of overall SO_2 removed by all types of SO_2 and sulfur removal technology including flue gas desulfurization (FGD) systems and fuel pretreatment systems (such as coal cleaning, coal gasification, and coal liquefaction). Sulfur removed by a coal pulverizer or in bottom ash and flyash would also be included in the computation.

PARTICULATE MATTER EMISSIONS

The proposed particulate matter emission standard would limit emissions to 13 ng/J (0.030 lb/million Btu) heat input. The proposed opacity standard would limit the opacity of emissions to 20 percent (6-minute average). If an affected facility exhibits opacity levels higher than 20 percent, while at the same time demonstrating compliance with the particulate matter standard, then a source-specific opacity standard may be established under 40 CFR 60.11(e).

NO_x EMISSIONS

The proposed NO_x emission standards vary according to fuel characteristics as follows:

(1) 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal.

(2) 260 ng/J (0.60 lb/million Btu) heat input from the combustion of bituminous coal.

In addition, separate standards are being proposed for gaseous and liquid fuels not derived from coal, lignite from certain areas, and coal refuse.

RATIONALE

SO_2 STANDARDS

Under section 111(a) of the Act, a standard of performance must reflect the degree of emission limitation and percentage reduction achievable through the application of the best technological system of continuous emission reduction taking into consideration cost and any nonair quality health and environmental impacts and energy requirements. In addition, credit is to be given for any cleaning of the fuel, or reduction in pollutant characteristics of the fuel, after mining and prior to combustion.

The 1977 amendments substantially changed the criteria for regulating new powerplants by requiring the application of technological methods of control to minimize SO_2 emissions and to maximize the use of locally available coals. Under the statute, these goals are to be achieved through revision of the standards of performance for new fossil fuel-fired stationary sources to specify (1) an emission limitation and (2) a percentage reduction requirement. According to legislative history accompanying the amendments, the percentage reduction requirement should be applied uniformly on a nationwide basis, unless the Administrator finds that varying requirements applied to coals of differing characteristics will not undermine the objectives of the House bill and other Act provisions.

The principal issue to be resolved in this rulemaking is whether a plant burning low-sulfur coal should be required to achieve the same percentage reduction in potential SO_2 emissions as those burning higher sulfur content coals.

Prior to framing alternative SO_2 standards, EPA evaluated control technology in terms of performance, costs, energy requirements, and environmental impacts. EPA has concluded that the proposed emission limits and control efficiencies are achievable with well-designed, maintained, and operated flue gas desulfurization systems but has not determined whether uniform application of these requirements is necessary to satisfy section 111 of the Act. EPA's final decision on this issue must be based on an assessment of the national, regional, and local environmental (air, water, and solid waste), economic, and energy impacts of both the uniform percentage reduction requirement and the other alternatives under consideration.

Toward this end, EPA performed extensive analyses of the potential impacts associated with each of the alternatives at the national, regional, and plantsite levels. Economic models were used for the purpose fo forecasting the nature of the utility industry in future years. Evaluation of the data revealed that the results predicted by the model were very sensitive to such assumptions as the rate of growth predicted for the industry, coal and oil prices, and transportation costs. Forecasts which assume low growth in electricity demand and high oil and rail transportation prices resulted in modeled estimates which show relatively small differences in the impacts of the alternatives at the national level. On the other hand, if assumptions of high growth in demand for electricity are combined with low oil and rail transportation prices, more significant economic, energy, and environmental impacts are predicted.

The Agency believes that it would be inappropriate to make a decision on the choice between the full and partial control alternatives without additional analyses of the modeling results. The model is being refined, with particular emphasis being placed on the assumptions used. Comment on the appropriateness of the selected assumptions and the relative significance of environmental, energy, and economic impacts are invited.

At the plant level, the partial control alternative would result in substantiallymore SO_2 emissions than full control when low-sulfur coal is fired. For example, a Western plant burning low-sulfur coal could emit as much as four times as much SO_2 under the partial control alternative as under full control. However, there are many plant locations where the cost of mandated emission control equipment can be an important factor in the utility's choice of coal to be fired. If partial control is permitted when low-sulfur coal is burned, the lower capital and operating costs associated with the control equipment may justify a decision to use more expensive low-sulfur coal. The same plant might have chosen cheaper high-sulfur coal if the same control equipment were required for all coals. In such a case, a partial control approach could result in lower emissions than a full control approach. For example, a 500 MW low-sulfur coal plant with partial control might emit 10,000 tons per year while the same plant burning high-sulfur coal under full control might emit some 15,000 tons per year.

The benefits of such shifts from high- to low-sulfur coal must be compared to the costs associated with foregoing increased local coal production. When considering local coal impacts, it must be noted that coal production will increase over current levels in all areas of the country under all control aternatives. This means local coal production impacts will affect the level of new production rather than displace existing production. The Administrator seeks comment on the relative significance of new coal production versus existing coal production as it pertains to the consideration of coal impacts in the final decision.

The economic impact of the standard can be viewed in a number of ways, depending on the economic measures selected and the manner in which they are used. While the capital and operating costs of control can be shown to be significant in absolute terms (e.g., billions of dollars), they can also be shown to be relatively small when compared to the hundreds of billions of dollars in new capital investment planned by the industry or to the approximately $100 billion annual revenue requirement projected for 1990. If the impact is considered in terms of monthly cost to the average consumer, the alternatives do not appear to have a major impact. However, when computed as a total cost to an average family over a 30- to 40-year period, the impacts can appear much more significant. In view of this, the Administrator solicits comments on which economic indicators are most appropriate and how the comparisons should be made.

A consideration in establishing the new source performance standards for powerplants is their relationship to the prevention of significant deterioration (PSD) program. Since virtually all new powerplants will have to comply with both the standards of performance and PSD requirements, concern has been expressed that the case-by-case best available control technology review under PSD creates the potential for prolonged public debate as to the adequacy of the control proposed for a given source. The likelihood of such debate, and the associated delays, would increase if a less stringent standard of performance is adopted. Consideration must also be given to the impact that a source complying with the revised standard of performance will have on the air quality increment. A source with lower emissions will use less of the available increment, thus providing a greater margin for growth. As mentioned above, the impact of this standard can be either to increase or to decrease emission rates for a given plant depending on the selection of the coal to be fired. In view of the above, the Administrator solicits comments as to how much weight should be given to PSD considerations when establishing the final standard of performance requirement.

PARTICULATE MATTER STANDARDS

The proposed standards would limit the emissions of particulate matter to 13 ng/J (0.03 lb/million Btu) heat input and would require a 99-percent reduction in uncontrolled emissions from solid fuels and a 70-percent reduction for liquid fuels. No particulate matter control would be necessary for units firing gaseous fuels alone, and thus a percent reduction would not be required. The 20-percent opacity (6-minute average) standard that is currently applicable to steam electric generating units (40 CFR Part 60, Subpart D) would be retained under the proposed standard to insure proper operation and maintenance of the particulate matter control system.

The proposed standards are based on the performance of a well designed and operated baghouse or electrostatic precipitator (ESP). EPA has determined that these control systems are the best adequately demonstrated systems of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact, and energy requirements).

This determination was reached after analyzing emission test results from steam generators firing both high- and low-sulfur coal and employing either ESP's or baghouses. Although the baghouse data were based on units of less than 44 MW, EPA has concluded that there are no technological barriers that would preclude their application on larger units. In addition, a number of large instalations are now under construction, and a 350-MW facility equipped with a baghouse for particulate emission control recently began operation.

EPA considered a standard of 21 ng/J (0.05 lb/million Btu) which could be met by wet particulate matter scrubbers in addition to baghouses and ESPs, but rejected this option because using scrubbers could increase emissions of fine particulate matter. A 21 ng/J standard would result in 60 percent higher emissions which could have an adverse effect on visibility. On the other hand, an advantage to allowing the use of scrubbers is that a single scrubber may be able to control both SO_2 and particulate matter.

It should be noted that there were no plants available for testing at which a well designed ESP or baghouse was followed by an FGD system; thus, the proposed standards are based on emission measurements taken at the particulate matter control device discharge prior to any FGD unit. Since there is the potential for an FGD system to affect particulate emissions, EPA is continuing to assess this situation. Of particular concern is the potential contribution of sulfuric acid mist to the measured particulate matter emissions. This issue is discussed in more detail under the particulate matter standards section of this preamble. EPA solicits comments and available data on this matter.

The proposed limit of 13 ng/J (0.03 lb/million Btu) will effectively preclude the use of ESPs on facilities using low sulfur coal and require baghouse control. DOE and the utility industry believe that baghouse technology has not been demonstrated sufficiently to require its use on utility size facilities. Because of this, DOE recommends that the standard be no less than 21 ng/J (0.05 lb/million Btu) while the industry recommends a standard of 34 ng/J (0.08 lb/million Btu). EPA requests comments on this this recommendation as well as on EPA's proposal.

NO_x STANDARDS

The proposed NO_x standards for different fuels are based on the emission limitations achievable through combustion modification techniques. Combustion modification limits NO_x formation in the boiler by reducing flame temperatures and by minimizing the availability of oxygen during combustion. The levels to which NO_x emissions can be reduced with combustion modification depend upon the type of fuel burned, boiler design, and boiler operating practice.

When considering these factors, EPA concluded that a uniform standard could not be applied to all fossil fuels or boiler types. In addition, EPA took into consideration the adverse side effects of low NO_x operation such as boiler tube wastage. As a result, different requirements were developed for bituminous and subbituminous coals.

The limitations for coal-derived liquid and gaseous fuels and shale oil are based on limits achievable with subbituminous coals. The limitations for liquid and gaseous fuels are the same as those promulgated in 1971 under 40 CFR part 60 subpart D for large steam generators. These requirements were not reexamined since few, if any, new oil- or gas-fired power plants are expected to be built. The recently promulgated limitations for lignite combustion (43 FR 9276) have been incorporated into these regulations without change because no new data have become available since their promulgation. Similarly, the exemption for combustion of coal refuse has also been retained.

BACKGROUND

In December 1971, under section 111 of the Clean Air Act, the Administrator promulgated standards of performance to limit emissions of SO_2, particulate matter, and NO_x from new, modified, and reconstructed fossil-fuel-fired steam generators (40 CFR 60.40 et seq.). Since that time, the technology for controlling these emissions has improved, but emissions of SO_2, particulate matter, and NO_x continue to be a national problem. In 1976, steam electric generating units contributed 24 percent of the particulate matter, 65 percent of the SO_2, and 29 percent of the NO_x emissions on a national basis.

The utility industry is expected to have continued and significant growth; approximately 300 new fossil-fuel-fired power plant boilers are to begin operation within the next 10 years. Associated with utility growth is the continued long-term increase in utility coal consumption from some 650 million tons/year in 1975 to between 1,400 and 1,800 million tons/year in 1990. Under the current performance standards for power plants, national SO_2 emissions are projected to increase approximately 15 to 16 percent between 1975 and 1990.

Impacts will be more dramatic on a regional basis. For example, in the absence of more stringent controls, utility SO_2 emissions are expected to increase tenfold to over 2 million tons by 1990 in the West South Central region of the country (Texas, Oklahoma, Arkansas, and Louisiana).

EPA was petitioned on August 6, 1976, by the Sierra Club and the Oljato and Red Mesa Chapters of the Navaho Tribe to revise the SO_2 standard so as to require a 90 percent reduction in SO_2 emissions from all coal-fired power plants. The petition included information to support the claim that advances in technology since 1971 called for a revision of the standard, and EPA agreed to investigate the matter thoroughly. On January 27, 1977 (42 FR 5121), EPA announced that it had initiated a study to complete the technological, economic, and other documentation needed to determine to what extent the SO_2 standard for fossil-fuel-fired steam generators should be revised.

On August 7, 1977, President Carter signed into law the Clean Air Act Amendments of 1977. The provisions under section 111(b)(6) of the Act, as amended, require EPA to revise the standards of performance for fossil-fuel-fired electric utility steam generators within 1 year after enactment.

After the Sierra Club petition of August 1976, EPA initiated studies to review the advancement made on pollution control systems at power plants. These studies were continued following the amendment of the Clean Air Act. In order to meet the schedule established by the Act, a preliminary assessment of the ongoing studies was made in late 1977. A National Air Pollution Control Techniques Advisory Committee (NAPCTAC) meeting was held on December 13 and 14, 1977, to present EPA preliminary data. The meeting was open to the public and comments were solicited.

The Clean Air Act Amendments of 1977 required the standards to be revised by August 7, 1978. When it appeared that EPA would not meet this schedule, the Sierra Club filed a complaint on July 14, 1978, with the U.S. District Court for the District of Columbia requesting injunctive relief to require, among other things, that EPA propose the revised standards by August 7, 1978. A consent order was developed and issued by the court requiring the EPA Administrator to (1) deliver the proposal package to the office of the Federal Register by September 12, 1978, and (2) promulgate the final standards within 6 months after proposal

The purpose of this proposal is to respond to the petition of the Navaho Tribe and Sierra Club, and to initiate the rulemaking required under section 111(b)(6) of the Act.

APPLICABILITY

The proposed standards would apply to all electric utility steam generating units (1) capable of firing more than 73 MW (250 million Bty/per hour) heat input of fossil fuel (approximately 25 MW of electrical energy output) and (2) for which construction is commenced after September 18, 1978.

On December 23, 1971, EPA promulgated, under subpart D of 40 CFR Part 60, standards of performance for fossil-fuel-fired steam generators used in electric utility and large industrial applications. The proposed standards will not apply to electric utility steam generating units originally subject to those standards (subpart D) unless the affected facilities are modified or reconstructed.

ELECTRIC UTILITY STEAM GENERATING UNITS

An electric utility steam generating unit is defined as any steam electric generating unit that is physically connected to a power distribution system and is constructed for the purpose of selling for use by the general public more than one-third of its maximum electrical generating capacity. Any steam that could be sold to produce electrical power for sale is also included when determining applicability of the standard.

INDUSTRIAL FACILITIES

Industrial steam electric generating units with heat input above 73 MW that are constructed for the purpose of selling more than one-third of their maximum electrical generation capacity (or steam generating capacity used to produce electricity for sale) would be covered under the proposed standards. Industrial steam generating units with a heat input above 73 MW that produce only steam or that were constructed for the purpose of selling less than one-third of their electric generation capacity are not covered by the proposed standards, but will continue to be covered under subpart D.

COGENERATION

Electric cogeneration units (steam generating units that would produce steam used for electric generation and process heat) would be considered electric utility steam generating units if they: (1) Were capable of combusting more than 73 MW of fossil fuel and (2) would be physically connected to a power distribution system for the purpose of selling for use by the general public more than one-third of their maximum electrical generating capacity. Cogeneration facilities that would produce power only for "in-house" industrial use would be considered industrial boilers and would be covered under subpart D if applicable.

RESOURCE RECOVERY UNITS

Steam electric generating units that combust nonfossil fuels such as wood residue, sewage sludge, waste material, or municipal refuse (either aone or in combination with fossil fuel) would only be covered by the proposed standards if the steam generating unit is capable of firing more than 73 MW of fossil fuel. If only municipal refuse were fired and the unit was not capable of being fired with more than 73 MW of fossil fuel, the unit would be considered an incinerator and the standards under subpart E would apply. Similarly, the standards under subpart O for sewage treatment plants would apply if only sewage sludge were burned.

COMBINED-CYCLE GAS TURBINES

The proposed standards would cover boiler emissions from electric utility combined-cycle gas turbines that are capable of being fired with more than 73 MW (250 million Btu-hour) heat input of fossil fuel in the steam generator, and where the unit is constructed for the purpose of selling more than one-third of its electrical output capacity to the general public. Electric utility combined-cycle gas turbines that use only turbine exhaust gas to heat a steam generator (waste heat boiler) or that are not capable of being fired with more than 73 MW of fossil fuel in the steam generator would not be covered by the proposed standards.

ISSUES ON APPLICABILITY

Noncontinental areas. There are several island areas that would be affected by the proposed standards. Because ot the unique characteristics of these areas, it is expected that all of their future power plants will use oil rather than coal. The issue is whether these new oil-fired units should be subject to the proposed 85 percent reduction, which would effectively require the use of FGD or equivalent systems, or to allow the use of low sulfur oil. After considering the costs of requiring FGD systems in light of the limited land area available for sludge disposal, EPA has decided to propose an exception for these facilities from the 85 percent reduction requirement. They would have to comply with the proposed SO_2 limit for oil-fired facilities of 340 ng/J (0.80 lb/million Btu) as well as all other proposed standards (see section 4.4 of EPA 450/2-78-007a-1).

Anthracite coal and Alaskan coal. The proposed standards would cover facilities combusting low sulfur anthracite coal or Alaskan coal in the same manner as all other coals.

EPA realizes, however, there are arguments in favor of allowing less stringent standards because of unique factors for both coals.

With respect to Alaskan coal, it is argued that the unique climatic conditions in Alaska coupled with the very low sulfur content of the coal makes it unreasonable to apply the same percent reduction requirement for SO_2 emissions to power plants located in that State. Anthracite is also low in sulfur content, but it is more expensive to produce than other locally available coals. In view of this, proponents of anthracite argue that if control cost were reduced through a less stringent standard, anthracite could then compete with locally available high sulfur content bituminous coal (see section 4.7.2 of EPA 450/2-78-007a-1).

Emerging technologies. Various groups expressed concern that if the proposed standards were rigidly applied, the development of new and promising technologies might be discouraged. They suggested that the innovative technology waiver provisions under the Clean Air Act Amendments of 1977 are not adequate to encourage certain capital-intensive, front-end control technologies. Under the innovative technology waiver provisions (section 111(j) of the Act) the Administrator may grant waivers for a period of up to 7 years from the date of issuance of the waiver or up to 4 years from the start of operation of a facility, whichever is less. Although this amount of time may be sufficient to amortize the cost of tail-gas control devices that do not achieve their design control level, it does not appear to be sufficient for amortization of high-capital-cost, front-end control technologies. For most front-end control technologies, modification or retrofit may be economically unreasonable.

To mitigate the potential impact on emerging front-end technologies, EPA proposes to establish slightly less stringent requirements for initial full-scale demonstration plants. This should insure that these standards do not preclude the development of new front-end technologies and should compensate for problems that may arise when applying them to commercial-scale facilities. The 85 percent SO$_2$ control requirement and the 210-ng/J NO$_x$ standard will provide developers of new technologies a clear environmental control objective for commercial facilities. However, if the Administrator subsequently finds that a given emerging technology (taking into consideration all areas of environmental impact, including air, water, solid waste, toxics, and land use) offers superior overall environmental performance, alternative standards would then be established by the Administrator.

Under the proposal, the Administrator (in consultation with the Department of Energy) would issue commercial demonstration permits for the first three full scale demonstration facilities of each of the technologies listed in the following table. These technologies have been shown to have the potential to achieve the standards established for commercial facilities. Under such permits, an 80 percent SO$_2$ control level (24-hour average) or a 300 ng/J (0.70 lb/million Btu) NO$_x$ emission limitation for liquid fuel derived from bituminous coals would be established. If the Administrator (in consultation with the Department of Energy) finds that additional demonstration of a given technology is necessary, additional permits may be issued. No more than 15,000 MW equivalent electrical capacity would be allocated for the purpose of commercial demonstrations under this proposal. This capacity would be allocated as follows:

Technology	Pollutant	MW Equivalent electrical capacity
Solvent refined coal	SO$_2$	6,000-10,000
Fluidized bed combustion (atmospheric).	SO$_2$	400-3,000
Fluidized bed combustion (pressurized).	SO$_2$	200-1,200
Coal liquefaction	NO$_x$	750-10,000

The capacity is presented in ranges because of uncertainty as to the amount that will be required for any one technology. This use of ranges should not be construed to mean that more than 15,000 MW would be allocated for purposes of commercial demonstration permits.

It should be noted that these permits would only apply to the application of this standard and would not supercede the new source review procedures and prevention of significant deterioration requirements under section 110 of the Act.

Finally, concern has been expressed as to whether emerging technologies should be required to comply with the proposed particulate standard. Since this concern is based on the same arguments that have been offered in regard to conventional technologies, consideration of special provisions will be tied to the final decision on the particulate emission limitation.

Modifications. The question has been raised whether the use of shale oil coal-based fuels such as coal/oil mixtures or solvent-refined coal in a boiler originally designed for oil firing is considered a modification under 40 CFR 60.14(c). In response, EPA proposes that shifting an existing oil-fired steam generator to coal/oil mixtures, shale oil, or coal-derived fuels, would not be considered a modification and the facility would not be subject to the proposed standards.

SO$_2$ STANDARDS

General Requirements. The proposed standards for SO$_2$ emissions would require:

1. Reduction of potential SO$_2$ emissions for solid, liquid, and gaseous fuels by 85 percent (24-hour average control efficiency) except for 3 days per month when no less than 75 percent is allowed.
2. Maximum allowable emissions from solid fuel of 520 ng/J (1.2 lb/million Btu) heat input 24-hour average except for the 3 days per month when the 75 percent is allowed.
3. Maximum allowable emissions from liquid or gaseous fuels of 340 ng/J (0.80 lb/million Btu) heat input 24-hour average except for 3 days per month.
4. Maximum control level of 86 ng/J (0.20 lb/million Btu) heat input 24-hour average.

DISCUSSION

The proposed standards are based on emission levels and the percentage reduction achievable with a well designed, operated, and maintained flue gas desulfurization (FGD) system. EPA believes the following types of FGD systems are capable of achieving the proposed standards: lime, limestone, Wellman-Lord, magnesium oxide, and double alkali. In determining that FGD is the best system of continuous emission reduction that has been adequately demonstrated for removal of SO$_2$, EPA assessed the costs of achieving the proposed standards and the nonair quality health and environmental impacts and energy requirements. Although the proposed standards are based on the performance of FGD systems, the use of other systems should not be discouraged. In this regard, a number of emerging technologies show promise.

The proposed percentage reduction requirement would apply to the combustion of all fossil fuels unless the emission level of 86 ng/J (0.20 lb/million Btu) is constantly attained (24-hour average basis). In effect, this means that all coal-fired and residual-oil-fired plants would be required to install FGD or equivalent SO$_2$ emission control systems. On the other hand, the emission level of 86 ng/J would permit certain clean fuels, such as wood waste, to be burned without FGD or at a very low percentage of reduction.

The emission limitations of 520 ng/J (1.2 lb/million Btu) for solid fuels and 340 ng/J (0.80 lb/million Btu) for liquid and gaseous fuels would place a maximum limit on SO$_2$ emissions regardless of percentage of SO$_2$ reduction attained and thus restrict the amount of sulfur in the fuel fired.

In determining that FGD systems were adequately demonstrated and that they could attain the proposed limitations, EPA has conducted a number of studies either directly or through consultants. To evaluate the relative performance of FGD systems, EPA has conducted tests at various sites. Several absorber designs and absorbents were tested at the Shawnee 10-MW test facility, emission tests were performed at various full-scale operations, and performance results from other test facilities and scrubber installations were surveyed, both in the United States and Japan. A detailed summary of the results from these studies is provided in section 4.2 of the supplement to the Background Information document for SO$_2$ (EPA 450/2-78-007a-1). In addition, all of the study reports are available in the docket for review (see listing set forth later in this preamble).

PERCENTAGE REDUCTION REQUIREMENT

In establishing the percentage reduction requirement for potential SO_2 emissions for solid, liquid, and gaseous fuels, EPA considered the SO_2 removal efficiency of prototype, pilot-scale, and commercial-scale FGD systems. EPA's considerations included measured variability of percentage reduction, effects of scrubber and coal sulfur variability on performance, effects of a spare module on scrubber reliability, and effects of design changes and maintenance practices on scrubber reliability.

To establish the variation of FGD system removal efficiency and the effects of varying sulfur content of coal on measured 24-hour-average SO_2 removals, EPA obtained continuous monitoring data from the Cane Run and Bruce Mansfield powerplants. These data were analyzed to establish the geometric standard deviations. Based on these analyses, EPA projected the mean SO_2 removal needed to comply with the proposed percentage reduction requirement. At the 99.99 percent confidence level, EPA concluded that an FGD system that could achieve a 92 percent long-term (30 days or more) mean SO_2 removal would comply with the proposed 85 percent (24-hour average) requirement.

With respect to long-term SO_2 removal efficiency, EPA has concluded that with certain practical changes in design, operation, and maintenance practices, lime/limestone FGD systems can achieve long-term SO_2 removal of 92 percent. FGD technologies employing more reactive absorbents such as magnesium oxide, additive magnesium-oxide-enriched lime, and sodium-based liquors can achieve SO_2 removal levesls of greater than 92 percent. For a more detailed discussion of these findings, please refer to section 4.2 of EPA 450/2-78-007a-1.

FGD AVAILABILITY

With respect to conditions that may affect FGD availability, EPA has investigated such problems as:

1. Formation of scale in the absorber and associated equipment in lime and limestone systems leading to plugging and reduced capacity.
2. Plugging of mist eliminators, lines, and some types of absorbers.
3. Failure of ancillary equipment such as pumps, piping, pH-sensing equipment, reheaters, centrifuges, fans, and duct and stack linings.
4. Inadequate absorbent make-up preparation.

EPA has concluded that these problems can and have been solved through the improved design of components, proper selection of construction materials, appropriate sparing, good operating practices, and good maintenance. As a result, the availability of full-scale scrubbing facilities has increased steadily. (See EPA 600/7-78-032b.) When determining FGD availability, one must recognize that FGD systems are composed of FGD modules, each of which is a separate scrubbing system. Because FGD modules are not generally manufactured in sizes over 125-MW capacity, large powerplants use multiple FGD modules in parallel. When FGD modules, even those averaging 90 percent availability, are integrated into an FGD system, the probability that all modules in the system will be simultaneously available diminishes in proportion to the number of modules; therfore, spare FGD modules will be needed in most instances. Such spares were included in EPA's estimates of FGD costs. Even when high FGD module availabilities are attained, the FGD module will not be in service some of the time because of regularly scheduled maintenance operations or repairs needed to restore loss of scrubbing efficiency. Although the amount of time for such maintenance can be considerable (even continuous), there should be little adverse impact on plant operation. With spares, a module can be rotated out of operation for maintenance even at full electrical load conditions. Several plants now in operation employ such a system. At reduced electrical loads, all FGD modules will not be needed for SO_2 control. Periodically, the entire plant is taken out of service for servicing non-FGD system related components providing an opportunity for scheduled FGD maintenance.

EPA acknowledges that even with a good maintenance program and use of spare FGD modules it may not be possible to maintain complete FGD system control for a portion of a plant's operating hours. At these times, the proposed standards would require that the electric generating load be shifted to an alternative electric generating plant. This procedure is necessary to prevent bypassing of uncontrolled SO_2 emissions to the atmosphere.

Load shifting is normally feasible, but it will not be possible when emergency conditions exist. Emergency conditions are considered to be periods when a powerplant and other electrical generating equipment owned by the associated utility company are being operated at full operating capacity less the capacity equal to the largest single unit in the system. Under emergency conditions, the proposed standards would allow flue gas to be bypassed around an inoperable FGD module provided the facility is equipped with at least one spare module. The proposed standards would not require plants having capacity of less than 125 MW to have a spare module. Bypassing an FGD unit except under emergency conditions would be a violation of the standards.

The emergency condition provisions are necessary to maintain the electric utility's capability to meet electric demand when excess generating reserves are not available. A minimal amount of spinning reserves must be kept separate from the load shifting procedures to prevent "blackouts." Please refer to section 4.6 of EPA 450/2-78-007a-1 for a more detailed discussion of this matter.

ENVIRONMENTAL IMPACTS

A major consideration with respect to nonregenerable FGD systems is the disposal of sludge and contamination from wastewater; therefore, EPA had its consultants examine these potential problems in detail.

With respect to sludge disposal, the consultant examined a number of parameters including the quantification of solid wastes that would be generated by different regulatory options, plant sizes, coal sulfur contents, and scrubbing processes. In addition, untreated wastes were characterized by effects of scrubbing process variables on sludge chemistry, trace element content, and physical and chemical properties. Finally, the environmental impacts and costs of various disposal processes and practices were assessed. ("Controlling SO_2 Emissions from Coal-Fired Steam Electric Generators: Solid Waste Impact," EPA 600/7-78-044.)

From a companion analysis ("Review of New Source Standards for SO_2 Emissions from Coal-Fired Utility Boilers," vol. 1, sec. 3), it is estimated that under the 85-percent reduction requirement the quantity of sludge generated will increase from some 12 million metric tons dry basis (current standard) to some 55 million metric tons dry basis in 1995. These figures are conservative since they assume a high-growth rate in electrical demand (5.8 percent through 1985, and 5.5 percent thereafter). The quantity of sludge generated would be less under regulatory options that do not require a uniform application of the 85-percent reduction requirement.

To estimate the cost of sludge disposal, EPA assumed that dewatered sludge would be fixed with lime and fly ash and be impounded in a clay-lined pond. Based on this assumption, EPA estimates that the cost of disposal would be some $19 per dry metric ton including land costs.

In addition, a field disposal study, which has been underway for 3 years at TVA's Shawnee powerplant site, has not revealed any significant problems from impoundment of treated FGD wastes.

EPA has concluded from these studies that sludge can be disposed of in an environmentally sound manner at reasonable costs. EPA will continue to evaluate the costs and effectiveness of alternative disposal methods as part of the economic analyses to be conducted during the proposal period. Comments on alternative control methods are invited.

With respect to the potential water pollution impact, EPA's consultant examined alternative standards in terms of their effects on the quality and quantity of powerplant waste-water effluents, and the amount of water consumption. In addition, alternative SO_2 control systems were examined relative to their impact on the above. The potential environmental effects of SO_2 control on effluents were also examined, and alternative treatment processes were evaluated.

The water pollution impact report "Controlling SO_2 Emissions from Coal-Fired Steam Electric Generators: Water Pollution Impact," EPA 600/7-78-045, concluded that in the aggregate the volume and quality of waste streams from SO_2 control systems are affected very little by alternative standards and that all effluent streams can be treated to acceptable levels using proven, commercially available technologies. Similarly, a more stringent standard would have little effect on water demand when compared to total plant consumptive water use.

ALTERNATIVE TECHNOLOGY

A potential alternative to wet FGD systems is dry SO_2 scrubbing. One of the more effective designs incorporates the use of a spray dryer and baghouse. In this system a spray dryer (similar to a wet SO_2 scrubber) is used with lime, soda ash, or other reactants to scrub SO_2 from the flue gases. Because of the minimal use of water in the spray dryer (by design), no additional reheating is required. Following the spray dryer, a baghouse is used to collect all particulate matter (including SO_2 reactants).

Spray drying has been tested at pilot plants, and it may be capable of achieving 85 percent removal with lime, soda ash, and other reactants. Due to cost considerations, the system is principally limited to coals with less than 1.5-percent sulfur if lime is used. Full-sized spray-drying units for powerplant application have been ordered and are expected to begin operation in the early 1980's. (Refer to sec. 4.3 of EPA 450/2-78-007a-1.)

In addition, a combination of physical cleaning of the fuel in conjunction with FGD systems may be a viable option for reducing SO_2, depending on the particular characteristics of the coal being used.

MAXIMUM ALLOWABLE EMISSION LIMITATION

In selecting the proposed maximum allowable emission limitation, EPA had to take into consideration two primary factors: FGD performance and the impact of the limitation on high-sulfur coal reserves. In effect, FGD performance determines the maximum sulfur content of coals that can be fired in achieving compliance with the maximum allowable emission limitation. To estimate coal sulfur content which can be used, EPA projected SO_2 emissions based upon minimum FGD system performance (i.e., 75 percent SO_2 removal 3 days per month) and maximum daily average sulfur content. Two alternative maximum allowable emission levels were considered: (a) 520 ng/J with three exemptions per month that would be coincident with the proposed percentage reduction requirement, and (b) 520 ng/J with no exemptions.

An analysis of national and regional coal production in 1990 was performed for each option. There would be no significant differences in total national production with either option. The analysis included use of cleaned, midwestern coal when coal cleaning would be necessary to attain compliance with the limitation. Sufficient reserves would be available to satisfy national demand with either option. However, on a regional basis a limitation without exemptions could have the potential of dislocating some coal production in the Midwest.

Under either option, midwestern coal production would increase to about 300 million tons; however, the use of some coal reserves in this area would be restricted by the limitation without exemptions. In the States of Ohio, Illinois, and in western Kentucky, 60 or more percent of reserves might be restricted even if coal cleaning were used.

On the other hand, this analysis may overstate the potential impacts since coal mixing or other methods of reducing the maximum daily average coal sulfur content were not fully considered. In view of this, the Agency will continue to examine the need for exemptions and the appropriateness of more stringent maximum emission levels such as 410 ng/J (1.0 lb/million Btu) or 340 ng/J (0.80 lb/million Btu) during the comment period. (See section 4.7.1 of EPA 450/2-78-007a-1 for a more detailed discussion.)

Based on our present estimates of the potential impact upon midwestern coal reserves and production, EPA has proposed that the maximum allowable emission limitation should have a 3-day exemption coincident with the 3 days of 75-percent control in the percent reduction standard. However, the Agency specifically requests comments on the level of the emission limit and the appropriateness of the 3-day exemption.

MAXIMUM CONTROL LEVEL

Under the proposed SO_2 standard, a maximum control level would be established. Compliance with that control level would constitute compliance with the percentage reduction requirement. In developing the proposed standard, EPA has considered two alternatives. The first would establish the level of 86 ng/J (0.20 lb/million Btu). The second would establish a higher level. Values from 215 ng/J (0.50 lb/million Btu) to 340 ng/J (0.80 lb/million Btu) have been considered.

In essence, these options focus on the question of whether a powerplant burning low-sulfur coal should be required to achieve the same percentage reduction as those burning high-sulfur coal. The emission level of 86 ng/J would require virtually all coal-fired plants to reduce potential emissions by 85 percent. In addition, it would require the installation of FGD systems on oil-fired powerplants. Therefore, this option is commonly referred to as full scrubbing or full control. On the other hand, an emission level in the range of 215-340 ng/J would permit plants firing low-sulfur coal to reduce their emissions by less than 85 percent, hence the term partial scrubbing.

Proponents of partial scrubbing have argued that adoption of a limitation in the range of 215-340 ng/J would reduce scrubber costs and permit bypassing of a portion of the flue gas and thus alleviate the need for plume reheat and associated energy costs. since low-sulfur coal inherently emits less SO_2, proponents of partial scrubbing maintain that these benefits can be obtained by partial scrubbing without a significant increase in emissions nationally. Finally, it is argued that since coal-fired units would be cheaper to build and operate if partial scrubbing were allowed, less dependence would be placed on existing oil-fired units and turbines, and a significant saving of oil would be realized.

On the other hand, proponents of full control have maintained that plants firing low-sulfur coal should be subject to the same reduction requirement as those burning high-sulfur coal. They argue that the statutory requirements and legislative history of section 111 of the Clean Air Act Amendments of 1977 require a uniform percentage reduction requirement. They also point out that applying full scrubbing to low-sulfur coal is technologically less demanding and less expensive than applying full scrubbing to high-sulfur coal and that emissions from a plant burning low-sulfur coal would be up to four times greater under partial scrubbing than under full control. Finally, it is argued that adoption of full control will tend to promote the use of locally available, higher sulfur content coals, particularly in the Midwest.

ALTERNATIVE SO_2 STANDARDS

The following alternative standards for SO_2 have been suggested by DOE:

1. Eighty-five percent reduction of potential SO_2 emissions during each calendar month.
2. A maximum control level of 340 ng/J (0.80 lb SO_2/million Btu), not to be exceeded during any 24-hour period.
3. A minimum of 33-percent reduction of potential SO_2 emissions. The alternative standards would have the following operational characteristics:

Monthly averaging. There would be no daily restriction on the percent reduction in potential SO_2 emissions. The requirement would be that the total sulfur emissions summed over each calendar month be no more than 15 percent of the total sulfur content of the coal consumed. There would be no restriction on bypassing some or all of the flue gas, so long as the monthly percent reduction requirement is met. If the monthly requirement is not met, enforcement penalties would be applied on the basis of the number of individual 24-hour periods during which the percent reduction was less than 85 percent.

Maximum control level of 340 ng/J (0.80 lb SO_2/million Btu). Under this alternative, a sliding-scale-percent reduction would be required; the full 85-percent reduction would be required only when high-sulfur coals were used. Only the minimum percent reduction requirement would be enforced for 24-hour periods when SO_2 emissions would be 340 ng/J or less. Any 24-hour period when emissions are greater than 340 ng/J and reduction is less than 85 percent will be a violation of the percent reduction requirement. There would be no waivers or exemption for this daily requirement.

Minimum percent reduction requirement of 33 percent. Regardless of whether the resulting emissions would be lower than the 340 ng/J (0.80 lb/million Btu) emissions requirement, 33-percent reduction in potential SO_2 emissions would be required. This would assure that continuous emission reduction technology is applied to all coals, including those with the lowest naturally occurring sulfur content.

In addition to the DOE proposal, the utility industry, through the Utility Air Regulatory Group (UARG), has also suggested an alternative SO_2 standard. The industry proposal contemplates a sliding scale percentage production standard for sulfur-dioxide emissions under which the required percent reduction declines as sulfur content in the coal declines. Under the industry proposal, there would be a ceiling of 1.2 pounds of sulfur dioxide and the required percent reduction would range between 85-percent removal on a coal with uncontrolled emissions[1] of 8 pounds to 20-percent removal on coals with uncontrolled emissions of 1 pound or less. Specifically, for coals with uncontrolled emissions of 5.0 pounds of sulfur dioxide or greater, the constraining emissions limit would be 1.2 pounds of sulfur dioxide. For coals with uncontrolled sulfur-dioxide emissions of 5 pounds of sulfur dioxide, percent removal would be 76 percent and, in the range between 5 pounds and 4 pounds of uncontrolled emissions, percent removal would decline by 0.1 percentage point for each 0.1-pound decrease in uncontrolled emissions. For coals with uncontrolled emissions of 4 pounds of sulfur dioxide, percent removal would be 75 percent and, between 4 pounds and 3 pounds of uncontrolled emissions, percent removal would decline by 0.9 percentage point for each 0.1 pound decrease in uncontrolled emissions. For coals with 3 pounds of uncontrolled emissions, percent removal would be 66 percent, and between 3 pounds of sulfur dioxide and 2 pounds of sulfur dioxide, percent removal would decline by 1.3 percentage points for each 0.1-pound decrease in uncontrolled emissions. At 2 pounds of uncontrolled emissions percent removal would be 53 percent, and between 2 pounds and 1 pound of uncontrolled emissions, percent removal would decline by 3.3 percentage points for each 0.1 pound decline in uncontrolled emissions. For coals with 1 pound or less of uncontrolled emissions percent removal would be 20 percent.

Compliance with these sulfur-dioxide standards would be determined on a 30-day average. Industry has also recommended that consideration be given to establishing an emission ceiling of 1.5 pounds for coal with uncontrolled emissions over 8 pounds.

Comments on these alternative standards are invited.

ANALYSES OF ALTERNATIVES

In order to determine the appropriate form and level of control for the proposed standards, EPA has performed extensive analyses of the potential national impacts associated with the alternative standards. The Agency employed economic models to forecast the structure and operating characteristics of the utility industry in future years. These models project the environmental, economic, and energy impacts of alternative standards for the electric utility industry. The major analytical efforts were a preliminary analysis completed in April 1978 and a revised assessment completed in August 1978. While these analyses are preliminary and subject to change, the issues examined and the results obtained are summarized in this section and in the following tables. Further details of the analyses can be found in "Background Information for Proposed SO_2 Emission Standards-Supplement," EPA 450/2-78-007a-1.

Impacts analyzed. The environmental impacts of the alternative standards were examined by projecting pollutant emissions. The emissions were estimated nationally and by geographic region for each plant type, fuel type, and age category. The Agency is also evaluating the significance of waste products generated by the control technologies and their environmental impacts.

The economic and financial effects of the alternatives were examined. This assessment included an estimation of the utility capital expenditures for new plant and pollution control equipment as well as the fuel costs and operating and maintenance expenses associated with the plant and equipment. These costs were examined in terms of annualized costs and annual revenue requirements. The impact on consumers was determined by analyzing the effect of the alternatives on average consumer costs and average monthly residential bills. The alternatives were also examined in terms of cost per ton of SO_2 removal. Finally, the present value costs of the alternatives were calculated.

The effects of the alternative proposals on energy production and consumption were also analyzed. National coal use was projected and broken down in terms of production by geographic region and consumption by region. The amount of western coal shipped to the Midwest and East was also estimated. In addition, utility consumption of oil and gas was analyzed.

Major assumptions. Two types of assumptions have an important effect on the results of the analyses. The first group involves the model structure and characteristics. The second group includes the assumptions used to specify future economic conditions.

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[1] Uncontrolled emissions of sulfur dioxide are defined as twice the sulfur content of the coal measured in pounds per million Btu. For the purposes of this standard, sulfur content of the coal can be measured at the plant for unwashed coals and at the mine prior to washing, for washed coals. In calculating percent removal, sulfur content of the flue gas as it leaves the stack is compared with the uncontrolled emissions of the coal.

The utility model selected for this analysis can be characterized as a cost minimizing economic model. In meeting demand, it determines the most economic mix of plant capacity and electric generation for the utility system, based on a consideration of construction and operating costs for new plants and variable costs for existing plants. It also determines the optimum operating level for new and existing plants. This economic-based decision criteria should be kept in mind when analyzing the model results. These criteria imply, for example, that all utilities base decisions on lowest costs and that neutral risk is associated with alternative choices.

Such assumptions may not represent the utility decisionmaking process in all cases. For example, the model assumes that a utility bases supply decisions on the cost of constructing and operating new capacity versus the cost of operating existing capacity. Environmentally, this implies a tradeoff between emissions from new and old sources. The cost minimization assumption implies that in meeting the standard a new powerplant will fully scrub high-sulfur coal if this option is cheaper than fully or partially scrubbing low-sulfur coal. Often the model will have to make such a decision, especially in the midwest where utilities can choose between burning local high or imported western low-sulfur coal. The assumption of risk neutrality implies that a utility will always choose the low-cost option. Utilities, however, may perceive full scrubbing as involving more risks and pay a premium to be able to partially scrub the coal. On the other hand, they may perceive risks associated with long-range transportation of coal, and thus opt for full control even though partial control is less costly. Comments are solicited regarding the use of a cost optimization model to simulate utility decisions.

The assumptions used in the analyses to represent economic conditions in a given year have a significant impact on the final results reached. The major assumptions used in the EPA analyses are shown in table 1 and the significance of these parameters is summarized below. Comments are solicited regarding the assumptions used.

The growth rate in demand for electric power is very important since this rate determines the amount of new capacity which will be needed and thus directly affects the emission estimates and the projections of pollution control costs. A high electric demand growth rate results in a larger emission reduction associated with the proposed standards and also results in higher costs. The April analysis used a relatively high-growth rate consistent with last year's national energy policy studies. The August analysis used a lower growth projection which is more in line with current estimates of demand growth.

The nuclear capacity assumed to be installed in a given year is also important to the analysis. Because nuclear power is less expensive, the model will predict construction of new nuclear plants rather than new coal plants. Hence, the nuclear capacity assumption affects the amount of new coal capacity which will be required to meet a given electric demand level. In practice, there are a number of constraints which limit the amount of nuclear capacity which can be constructed. The assumptions used in the EPA analyses assume high (April) and moderate (August) growth in nuclear capacity.

The oil price assumption has a major impact on the amount of predicted new coal capacity, emissions, and oil consumption. Since the model makes generation decisions based on cost, a low oil price relative to the cost of building and operating a new coal plant will result in more oil-fired generation and less coal utilization. This results in less new coal capacity which reduces capital costs but increases oil consumption and fuel costs because oil is more expensive per Btu than coal. This shift in capacity utilization also affects emissions, since an existing oil plant generally has a higher emission rate than a new coal plant even when only partial control is allowed on the new plant.

Coal transportation and mine labor rates both affect the delivered price of coal. The assumed transportation rate is generally more important to the predicted consumption of low-sulfur coal since that is the coal type which is most often shipped long distances. The assumed mining labor cost is more important to eastern coal costs and production estimates since this coal production is generally much more labor intensive than western coal. The model does not incorporate the Agency's PSD regulations or forthcoming requirements to protect and enhance visibility. These requirements may be important factors for new powerplants.

Summary of results. The results of the EPA analyses which were completed in April and August 1978 are presented in tables 2 through 8 and discussed below. Four alternative standards were evaluated. Each of the options presented includes 85-percent control of inlet SO_2 (24-hour average), except for 3 days per month, a maximum SO_2 emission limit of 520 ng/J (1.2 lb/million Btu) except for 3 days per month, a particulate matter standard of 13 ng/J (0.03 lb/million Btu), and the proposed NO_x standards. The partial control options in the tables represent alternative levels for the maximum control level required on a 24-hour basis.

The projected SO_2 emissions from utility boilers are shown by plant type and geographic region in tables 2 through 5. Table 2 details the 1990 national SO_2 emissions resulting from different plant types and age groups. As is expected, the proposed standards result in a significant reduction of SO_2 emissions as compared to the current standards. This reduction ranges from 10 to 12 percent depending on the alternative examined and the assumptions used. The emissions from new plants directly affected by the standards are reduced by up to 73 percent. However, the model predicts that the proposed standards will delay the construction of new plants (note the total coal capacity changes) causing existing coal- and oil-fired plants to be utilized more than they would have been without the proposed standards. This causes an increase in emissions from existing plants which offsets part of the reduction achieved by new plants. As discussed above, this shift in capacity utilized is predicted by the costs minimiization model as a result of increased pollution control cost for new coal-fired plants. This shift in the generation mix has important implications for the decisionmaking process. For example, if a national energy policy phases out oil use for electric power generation, then the April study's prediction (table 6) of increased oil use in 1990 (over 1975 levels) will not be allowed to occur. With such a policy, oil consumption impacts would be similar to those shown for the August analysis in table 6.

A summary of the projected 1990 regional SO_2 emissions under the alternative control levels is shown in table 3. The combined emissions in the East and Midwest are reduced about 7 percent as compared to predictions under the current standards. These emissions are not affected greatly by the various control options, although there is a slight increase shown under the 340 ng/J (0.80 lb/million Btu) option in the April analysis. The combined emissions in the west south-central and west regions show a greater variation on a percentage basis. In the analysis, the full control and 210 ng/J (0.50 lb/million Btu) options both result in a 36-percent reduction from emission levels under the current standards, while the 340 ng/J (0.80 lb/million Btu) option results in a 28-percent decrease.

Regional emissions from the new plants directly affected by the proposed standards are shown for the years 1990 and 1995 in tables 4 and 5. These tables also project the coal consumption and emission factors (million tons of SO_2 per quadrillion Btu) for the new plants. The latter figures are shown to illustrate the effect of changes in the amount of new capacity and variations in the utilization of the new capacity. As noted above, the 1990 emissions from new plants drop dramatically under the proposed standards to a level only about one-third that which would result under the current standards. This emission reduction is due in part to lower emission factors and in part to reduced coal consumption predicted by the model. Coal consumption in the East is virtually unchanged, but in the Midwest coal consumption in new plants drops by one-third as a result of the proposed standards. In the west south-central and west regions coal consumption drops 5 to 10 percent which is about the same as the decline in national coal consumption at new plants. The reduced coal consumption in new plants results from a delay in new plant construction due to the increased cost of generation from new coal plants. Reduced coal consumption by new plants means a shift to more coal and oil burned in existing plants or new turbines, and this causes the increase in emissions from existing and oil-fired plants which was mentioned earlier. Table 5 shows that in 1995 the emission reduction due to the proposed standards is still of the same magnitude as the 1990 reduction. Also, since coal capacity is similar under all options by 1995, the coal consumption impact of the proposed standards is less pronounced. Changes in coal consumption in 1995 are almost entirely due to variations in the utilization of the new plants.

Table 6 illustrates the effect of the proposed standards on 1990 national coal production, western coal shipped east, and utility oil and gas consumption. This table shows some large differences between the two analyses which are caused by different model assumptions. For example, in the model, higher oil prices decrease oil demand and increase coal use. Increasing transportation costs increases the delivered price of western coal and reduces demand. These two factors along with the lower growth rate account for most of the difference in fuel use estimates between the April and August results. However, the conclusions drawn from the analyses are similar. For example, in terms of coal production, both analyses show that total production will increase in all regions of the country as compared to 1975 levels.

Compared to production under the current standards, the April analysis predicts an increase in eastern coal production under all but the 340 ng/J (0.80 lb/million Btu) option. Midwestern production increases under all options, and western production decreases under all but the 340 ng/J (0.80 lb/million Btu) option. Western coal shipped east is lower under all options than under the current standard, but is still 14 to 20 times higher than 1975 levels. Finally, the April analysis projects that oil consumption by utilities would be increased by the proposed standards. The increase varies from 300,000 barrels per day for the full control option to 100,000 barrels per day for the 210 ng/J (0.50 lb/million Btu) and 340 ng/J (0.80 lb/million Btu) options.

The August figures predict a smaller increase in 1990 eastern coal production than would be expected under the current standards. Midwestern production increases by 15 to 43 million tons and western production decreases up to 56 million tons. The amount of western coal shipped east is reduced by 30 million tons by both full control and 210 ng/J (0.50 lb/million Btu) options, and is essentially unchanged by the higher options. Due to the high assumed oil price, oil consumption is reduced from current levels, but the 1990 difference between the options and the current standards is still an increase of 200,000 to 300,000 barrels per day. This increased oil consumption results from the predicted shift toward existing oil-fired plants and turbines as a result of higher pollution control costs for new coal plants. Table 8 shows that as high oil prices are assumed (August analysis), there is no difference in 1995 oil consumption among the options. Finally, the DOI/DOE coal leasing study (see "Other Studies") shows a difference of about 50,000 barrels per day in 1990 between full and partial scrubbing.

The economic effects of the proposed standards are shown in table 7 for 1990. Utility capital expenditures between 1979 and 1990 increase under all options as compared to the $500 to $750 billion estimated to be required in the absence of a change in the standard. The capital estimates in tables 7 and 8 are increments over the expenditures under the current standard and include both plant capital (for new capacity) and pollution control expenditures. As shown in table 2, the model estimates total industry capacity is to be 10 GW to 15 GW greater under the partial control option, and the cost of this extra capacity makes the total utility capital expenditures higher under the 210 ng/J (0.50 lb/million Btu) and 340 ng/J (0.80 lb/million Btu) options, even though pollution control capital is lower than under the full control option.

Annualized cost includes a levelized capital charge, fuel costs, and operation and maintenance costs associated with utility equipment. All of the options cause an increase in annualized cost over the current standards. This increase varies, depending on the assumptions modeled, from $300 million to $2 billion or a 1- to 2-percent increase over the $90 to $100 billion.

The average monthly residential electric bill is predicted to increase only slightly by any of the options, up to a maximum 2-percent increase shown for full control in the April analysis. The large total increase in the monthly bill over 1975 levels is due in large part to a more than 50-percent increase in the amount of electricity used by each customer. Pollution control expenditures, including those to meet the current standards, account for about 15 percent of the increase in the average monthly bill while the remainder of the cost increase is due to capacity expansion and general cost escalations.

The average monthly bill is determined by estimating utility revenue requirements which are a function of capital expenditures, fuel costs, and operation and maintenance costs. Therefore, due to changes in the pattern of expenditures, the selection of the specific year examined has an impact on the costs shown. For example, the August analysis shows slightly higher cost in 1990 for the partial control options as compared to full control. This is due to the larger amount of new capacity and the higher associated capital costs under these options. By 1995, the amount of new coal capacity under each option has approximately equalized, and the estimates show full control to be most expensive but by only 12 cents a month over the average bill under the 340 ng/J (0.80 lb/million Btu) option (table 8).

The incremental costs per ton of SO_2 removal are also shown in table 7. The figures are determined by dividing the change in annualized cost by the change in annual emissions, as compared to the current standards. These ratios are a measure of the cost effectiveness of the options, where lower ratios represent a more efficient resource allocation. All the options result in higher cost per ton than the current standards with the full control option being the most expensive.

Another measure of cost effectiveness is the average dollar-per-ton cost at the plant level. This figure compares total pollution control cost with total SO_2 emission reduction for a model plant. This average removal cost varies depending on the level of control and the coal sulfur content. The range for full control is from $260 per ton on high-sulfur coal to $1,600 per ton on low-sulfur coal. The partial scrubbing range is from $900 per ton on low-sulfur coal to $2,000 per ton on very low sulfur coal.

The economic analysis also estimated the present value cost in order to facilitate comparison of the options by reducing the streams of capital, fuel, and operation and maintenance expenses to one number. A present value estimate allows expenditures occurring at different times to be evaluated on a similar basis by discounting the expenditures back to a fixed year. Two types of present value costs have been estimated in the analysis.

First, an estimate was made of the present value of costs which will be faced by the consumers. Essentially, this represents the present value of utility revenue requirements. This calculation for the August results shows a 1990 present value of $26 billion for the full control option and $15 billion for the 340 ng/J (0.80 lb/million Btu) option as compared to the current standards.

Second, an "economic" or "real resource" present value was estimated. Real resource present value is designed to measure the level of national resources committed to the standards. In computing this resource commitment, construction costs, labor costs, and other resource costs were considered, but financing flows and transfer payments were excluded. Thus, allowance for funds during construction, depreciation, interest, taxes, and other indirect flows were excluded. This second type of present value figure gives an estimate of the costs to society of the options. The calculation of this value based on the August analysis results in a 1990 present value of $9.8 billion for full control and $10.4 billion for the 340 ng/J (0.80 lb/million Btu) option. Both types of present value costs were estimated as an increment over the current standards for the years 1990 and 1995. These figures include capital costs of plants installed through that date and operation and maintenance costs for 30 years after the cutoff date. Comments are solicited regarding the calculation and use of present values for this decision. Comments are also solicited on the appropriateness of using present value costs to the utility or present value resources costs to society.

A summary of the 1995 impacts of the proposed standards is shown in table 8 based on the August analysis. The total coal capacity figure shows that by 1995 all the options have equal capacity. Thus, the options reflect differences in amount of low-sulfur coal use, control, equipment, and variation in capacity utilization. In general, full control results in slightly lower emissions, less Western coal shipped East, higher capital expenditures, and slightly higher average residential bills than would result under the partial control options.

Other studies. In addition to the studies described above, EPA is aware of three other major studies of the impacts resulting from several recommended standards for powerplants. One of these studies was performed as a joint effort of the Departments of the Interior and Energy for studying coal leasing policies. Another analysis was done by the Department of Energy, and the third study was sponsored by a segment of the electric utility industry. These studies were performed for the purpose of analyzing the impacts of their respective recommended standards along with the EPA options discussed above. The results of these studies have been considered by EPA in developing the proposed standards. More detail on the results of these studies is given in the supplement to the background document (EPA 450/2-78-007a-1).

Table 1. COMPARISON OF ASSUMPTIONS
April 1978 and August 1978

Assumption	April	August
Growth rates	1975-1985: 5.8%/yr 1985-1995: 5.5%	1975-1985: 4.8%/yr 1985-1995: 4.0%
Nuclear capacity	1985: 108 GW 1990: 177 1995: 302	1985: 97 GW 1990: 167 1995: 230
Oil prices ($ 1975)	1985: $13/bbl 1990: $13 1995: $13	1985: $15/bbl 1990: $20 1995: $28
General inflation rate	5.5%/yr	5.5%/yr
Annual emissions @ 0.5 floor	0.5 lb SO_2/million Btu	0.32 lb SO_2/million Btu
Coal transportation	Increases at general inflation rate	Increases at general inflation rate plus 1%
Coal mining labor costs	Increases at general inflation rate	Increases at general inflation rate plus 1%
Miscellaneous	A number of miscellaneous changes were made between the April 1978 study and the August 1978 study. These changes were either corrections or refinements of values used in the April study. Examples of these changes included revisions to the level of SIP control assumed in the model, revisions to the scrubbing costs, changes in the assumptions regarding industrial coal consumption, and changes to the coal supply curves used in the April study.	

Table 2. SUMMARY OF NATIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS[a]
(million tons)

Plant Category	Level of Control										
	1975 Actual	Current Standards		Full Control		Partial Control					
						- 210 ng/J		290 ng/J		... 340 ng/J	
		APR	AUG	APR	AUG	APR	AUG	APR	AUG	APR	AUG
SIP/NSPS Plants[b]	–	16.8	16.0	17.2	16.2	16.9	16.2	–	16.1	16.7	16.1
New Plants[c]	–	4.2	4.4	1.5	1.2	2.1	1.3	–	1.5	3.3	1.8
Oil/Gas Plants	–	2.3	1.1	2.5	1.4	2.3	1.2	–	1.2	2.3	1.2
Total National Emissions	18.6	23.3	21.4	21.1	18.9	21.3	18.8	–	18.9	22.3	19.1
Total Coal Capacity (GW)	205	465	451	444	428	460	439	–	440	460	444

SOURCE: Background Information for Proposed SO_2 Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapters 2 and 3, August 1978.

[a] Results of EPA analyses completed in April 1978 and August 1978.

[b] Plants subject to existing state regulations or the current NSPS of 1.2 lb SO_2/million Btu.

[c] Plants subject to the revised standards.

Table 3. SUMMARY OF 1990 REGIONAL SO_2 EMISSIONS FOR UTILITY BOILERS[a]
(million tons)

	Level of Control										
	1975 Actual	Current Standards		Full Control		Partial Control 210 ng/J		290 ng/J		340 ng/J	
		APR	AUG	APR	AUG	APR	AUG	APR	AUG	APR	AUG
Total National Emissions	18.6	23.3	21.4	21.1	18.9	21.3	18.8	–	18.9	22.3	19.1
Regional Emissions											
East[b]	9.1	10.8	10.2	9.7	9.0	9.6	9.0	–	8.9	10.2	9.0
Midwest[c]	8.8	8.7	7.8	8.5	7.6	8.4	7.6	–	7.6	8.6	7.6
West South Central[d]	0.2	2.6	2.3	1.8	1.5	2.0	1.4	–	1.5	2.3	1.6
West[e]	0.5	1.3	1.3	1.1	0.8	1.2	0.9	–	0.9	1.3	1.0
Total Coal Capacity (GW)	205	465	451	444	428	460	439	–	440	460	444

SOURCE: Background Information for Proposed SO_2 Emission Standards-Supplement, EPA 450/2-78-0071-1, Chapters 2 and 3, August 1978.

[a] Results of EPA analyses completed in April 1978 and August 1978.

[b] New England, Middle Atlantic, South Atlantic, and East South Central Census Regions.

[c] East North Central and West North Central Census Regions.

[d] West South Central Census Region.

[e] Mountain and Pacific Census Regions.

Table 4. SUMMARY OF 1990 SO_2 EMISSIONS BY PLANTS SUBJECT TO THE PROPOSED STANDARDS: AUGUST 1978 ANALYSIS

	Level of Control				
	Current Standards	Full Control	Partial Control 210 ng/J	290 ng/J	340 ng/J
East[a]					
Total New Plant Emissions (million tons)	2.1	0.7	0.7	0.7	0.8
Coal Consumption (10^{15} Btu)	3.47	3.41	3.43	3.48	3.47
Emission Factor (#S/10^6 Btu)[b]	0.60	0.21	0.21	0.22	0.23
Midwest[c]					
Total New Plant Emissions (million tons)	0.60	0.2	0.2	0.2	0.2
Coal Consumption (10^{15} Btu)	1.17	0.79	0.80	0.81	0.81
Emission Factor (#S/10^6 Btu)[b]	0.48	0.21	0.21	0.23	0.26
West South Central[d]					
Total New Plant Emissions (million tons)	1.2	0.2	0.3	0.4	0.5
Coal Consumption (10^{15} Btu)	1.93	1.67	1.97	1.96	1.95
Emission Factor (#S/10^6/Btu)[b]	0.60	0.14	0.14	0.18	0.24
West[e]					
Total New Plant Emissions (million tons)	0.6.	0.1	0.2	0.2	0.3
Coal Consumption (10^{15} Btu)	1.25	1.19	1.18	1.19	1.24
Emission Factor (#S/10^6/Btu)[b]	0.40	0.09	0.14	0.19	0.24

SOURCE: Background Information for Proposed SO_2 Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapter 3, August 1978.

[a] New England, Middle Atlantic, South Atlantic, and East South Central Census Regions.

[b] Ratios may not be obtained exactly from figures shown here due to rounding.

[c] East North Central and West North Central Census Regions.

[d] West South Central Census Region.

[e] Mountain and Pacific Census Regions.

Table 5. SUMMARY OF 1995 SO_2 EMISSIONS BY PLANTS SUBJECT TO THE PROPOSED STANDARDS: AUGUST 1978 ANALYSIS

Level of Control

	Current Standards	Full Control	Partial Control 210 ng/J	Partial Control 290 ng/J	Partial Control 340 ng/J
East[a]					
Total New Plant Emissions (million tons)	4.0	1.3	1.3	1.4	1.5
Coal Consumption (10^{15} Btu)	6.73	6.39	6.47	6.49	6.67
Emission Factor (#S/10^6 Btu)[b]	0.60	0.21	0.21	0.21	0.22
Midwest[c]					
Total New Plant Emissions (million tons)	1.2	0.4	0.4	0.5	0.5
Coal Consumption (10^{15} Btu)	2.21	1.94	1.92	1.99	2.00
Emission Factor (#S/10^6 Btu)[b]	0.53	0.21	0.21	0.23	0.26
West South Central[d]					
Total New Plant Emissions (million tons)	1.6	0.4	0.4	0.5	0.7
Coal Consumption (10^{15} Btu)	2.63	2.77	2.73	2.70	2.68
Emission Factor (#S/10^6 Btu)[b]	0.60	0.15	0.15	0.19	0.25
West[e]					
Total New Plant Emissions (million tons)	1.1	0.2	0.3	0.4	0.5
Coal Consumption (10^{15} Btu)	2.28	2.32	2.29	2.27	2.27
Emission Factor (#S/10^6 Btu)[b]	0.44	0.09	0.13	0.19	0.22

SOURCE: Background Information for Proposed SO_2 Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapter 3, August 1978

[a] New England, Middle Atlantic, South Atlantic, and East South Central Census Regions.

[b] Ratios may not be obtained exactly from figures shown here due to rounding.

[c] East North Central and West North Central Census Regions.

[d] West South Central Census Region.

[e] Mountain and Pacific Census Regions.

TABLE 6. SUMMARY OF IMPACTS ON FUELS IN 1990[a]

Level of Control

	1975 Actual	Current Standards		Full Control		Partial Control 210 ng/J		Partial Control 290 ng/J		Partial Control 340 ng/J	
		APR	AUG	APR	AUG	APR	AUG	APR	AUG	APR	AUG
U.S. Coal Production (million tons)											
East	396	441	465	467	449	464	450	-	450	418	449
Midwest	151	298	275	375	318	353	316	-	294	307	290
West	100	1027	785	870	736	938	752	-	779	1055	784
TOTAL	647	1767	1525	1711	1502	1755	1517	-	1523	1780	1523
Western coal shipped east (million tons)	21	455	149	299	118	346	117	-	147	429	152
Oil/gas consumption in power plants (million bbl/day)	3.1	3.0	1.2	3.3	1.5	3.1	1.4	-	1.4	3.1	1.4

SOURCE: Background Information for Proposed SO_2 Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapter 2 & 3, August 1978

[a] Results of EPA analyses completed in April 1978 and August 1978.

Table 7. SUMMARY OF 1990 ECONOMIC IMPACTS[a]

	Level of Control									
	Current Standards		Full Control		------Partial Control 210 ng/J		290 ng/J		340 ng/J	
	APR	AUG	APR	AUG	APR	AUG	APR	AUG	APR	AUG
Average monthly residential bills ($/month)	45.31	43.89	46.39	44.22	46.20	44.48	-	44.30	45.47	4[illegible].38
Incremental Utility capital expenditures, cumulative 1976-1990 ($ billions)	-	-	10	0	15	8	-	4	3	[illegible]
Incremental Annualized cost ($ billions)	-	-	2.0	1.9	1.3	1.7	-	1.3	0.3	1.[illegible]
Incremental Cost of SO_2 Reduction ($/ton)	-	-	885	754	640	642	-	511	303	485

SOURCE: Background Information for Proposed SO_2 Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapters 2 & 3, August 1978.

[a] Results of EPA analyses completed in April 1978 and August 1978.

Table 8. SUMMARY OF 1995 IMPACTS: AUGUST 1978 ANALYSIS

	Level of Control					
	1975 Actual	Current Standards	Full Control	------Partial Control 210 ng/J	290 ng/J	340 ng/J
National Emissions (million tons)	18.6	23.3	18.5	18.5	18.7	19.0
New Plant Emissions[a] (million tons)	–	7.9	2.4	2.5	2.0	3.2
U.S. Coal Production (million tons)	647	1865	1865	1858	1860	1866
Western Coal Shipped East (million tons)	21	210	130	133	190	196
Oil/Gas Consumption (million bbl/day)	3.1	0.8	0.9	0.9	0.9	0.9
Incremental Cumulative Capital Expenditures (1975 $ billion)	–	–	32	26	20	19
Incremental Annualized Cost (1975 $ billion)	–	–	2.6	2.3	2.0	1.9
Average Monthly Residential Bill (1975 $/month)	–	45.34	46.22	46.13	46.12	46.10
Total Coal Capacity (GW)	198	507	580	580	500	580

SOURCE: Background Information for Proposed SO_2 Emission Standards-Supplement, EPA 450/2-78-007a-1, Chapter 3, August 1978.

[a] Plants subject to the revised standards.

PARTICULATE MATTER STANDARDS

The proposed standards would limit the emissions of particulate matter to 13 ng/J (0.03 lb/million Btu) heat input and would require a 99-percent reduction in uncontrolled emissions from solid fuels and a 70-percent reduction for liquid fuels. No particulate matter control would be necessary for units firing gaseous fuels alone, and thus a percent reduction would not be required for gaseous fuels. The 20-percent opacity (6-minute average) standard that is currently applicable to steam electric generating units (40 CFR Part 60, Subpart D) would be retained under the proposed standards. An opacity standard is proposed to insure proper operation and maintenance of the particulate matter control system. If an affected facility were to comply with all applicable standards except opacity, the owner or operator may request the Administrator under 40 CFR 60.11(e) to establish a source specific opacity standard for that affected facility.

The proposed standards are based on the performance of a well designed and operated baghouse or electrostatic precipitator (ESP). EPA has determined that these control systems are the best adequately demonstrated systems of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements).

EPA has evaluated data from more than 50 emission test runs conducted at eight baghouse-equipped, coal-fired steam generating units. The data from two tests exceeded the proposed standard, however, it is EPA's judgment that the emission levels at the two units which had measured emission levels above the proposed standards could be reduced to below the proposed standards through an improved maintenance program. EPA believes that baghouses with an air-to-cloth ratio of 0.6 actual cubic meters per minute per square meter (2 ACFM/ft^2) would achieve the proposed standards at pressure drops of less than 1.25 kilopascals (5 in. H_2O). EPA has concluded that this air/cloth ratio and pressure drop are reasonable when considering cost, energy, and nonair quality impacts.

EPA collected emission data from 21 ESP-equipped, coal-fired steam generating units. The nominal sulfur content of the coals being fired ranged from 0.4 percent to 1.9 percent. None of the 21 units tested were designed to achieve an emission level equal to or below the proposed standard of 13 ng/J (0.03 lb/million Btu) heat input; however, emissions from 9 of the 21 units were below the proposed standard. All of the units tested which were firing coal with a sulfur content greater than 1 percent and had a hot side ESP with a specific collection area greater than 89 square meters per actual cubic meter per second (452 ft^2/1,000 ACFM), or a cold side ESP with a specific collection area greater than 85 square meters per actual cubic meter per second (435 ft^2/1,000 ACFM), had emission levels below the proposed standards. EPA evaluated emission levels from units burning relatively low-sulfur coal because it is more difficult for an ESP to collect particulate matter emissions generated by the combustion of low-sulfur coal than high-sulfur coal. ESP's require a larger specific collection area when applied to units buring low-sulfur coal than to units burning high-sulfur coal, because the resistivity of the fly ash is higher with low-sulfur coal. To meet the proposed standard, EPA believes that an ESP used on low-sulfur coal would have to have a specific collection area from around 130 (hot side) to 200 (cold side) square meters per actual cubic meter per second (650 to 1,000 ft^2 per 1,000 ACFM) while an ESP used on high-sulfur coal (3.5 percent sulfur) would only require around 72 square meters per actual cubic meter per second (360 ft^2 per 1,000 ACFM).

ESP's have been traditionally used to control particulate emissions from powerplants. High-sulfur coal produces fly ash with a low electrical resistivity which can be readily collected with an ESP. However, low-sulfur coal produces fly ash with high electrical resistivity, which is more difficult to collect. The problem of high electrical resistivity fly ash can be reduced by using a hot side ESP (ESP located before combustion air preheater) when firing low-sulfur coal. Higher fly ash collection temperatures improve ESP performance by reducing fly ash resistivity for most types of low-sulfur coal (for example, increasing the fly ash collection temperature from 177° C (350° F) to 204° C (400° F) can reduce electrical resistivity of fly ash from low-sulfur coal by approximately 50 percent).

While EPA believes that ESP's can be applied to high-sulfur coal at reasonable costs to meet the proposed standards, it recognizes that applying a large, high efficiency ESP to a facility using low-sulfur coal to meet the proposed standards will be more expensive. In view of this, EPA believes that a baghouse control system could be applied on utility-size facilities firing low-sulfur coal at a lower cost than an ESP. Although the largest baghouse-controlled coal-fired steam generator for which EPA has particulate matter emission data is 44 MW, several larger installations are currently under construction, and EPA plans to test a 350-MW powerplant controlled with a baghouse which recently began operation. Since baghouses are designed and constructed in modules rather than as one larger unit, there should be no technological barriers to scaling them up to a utility sized facility. Twenty-four baghouse-equipped coal-fired utility steam generators are scheduled to be operating by the end of 1978 and an additional 30 units are planned to start operation after 1978. About two-thirds of these planned units will be larger than 150-MW electrical output capacity, and more than one-third of these planned baghouse systems will be for units being fired with coal containing more than 3 percent sulfur. EPA therefore believes that baghouses have been adequately demonstrated for even the largest utility-sized facility.

EPA collected emission test data from seven coal-fired steam generators controlled by wet particulate matter scrubbers. Data from five of the seven resulted in emission levels less than 21 ng/J heat input (0.05 lb/million Btu). Data from only one of the seven were less than 13 ng/J (0.02 lb/million Btu) heat input. In view of this, EPA believes that wet particulate matter scrubbers would not be capable of complying with the proposed standards under most conditions.

EPA considered proposing the standard at a level of 21 ng/J (0.05 lb/million Btu) in order to allow the application of wet particulate matter scrubbers in addition to baghouses and ESP's. This option was rejected, because EPA believes that allowing scrubbers would cause an increase in the emissions of fine particulate matter without compensating advantages. In addition to 60 percent higher emissions, a particulate matter scrubber would require three times as much energy to operate as a dry control system, and would also increase water consumption and waste water treatment requirements. An increase in fine particulate emissions would have an adverse effect on visibility. The primary suggested advantage to allowing the use of scrubbers for particulate matter control would be to allow a single scrubber to control both SO_2 and particulate matter emissions which would result in a cost savings.

The Department of Energy (DOE) and others believe that the proposed standard of 3 ng/J (0.03 lb/million Btu) will preclude the use of ESP's on facilities using low-sulfur coal and require baghouse control which they believe has not been demonstrated on utility-size facilities. Because of this, DOE recommends that the standard be no less than 21 ng/J (0.05 lb/million Btu). The Utility Air Regulatory Group (UARG) also maintains that baghouses have not been adequately demonstrated, particularly when firing high-sulfur coal. They further believe that ESP's cannot achieve the proposed standard of 13 ng/J at reasonable cost. In view of this, UARG recommends an emission limitation of 34 ng/J (0.08 lb/million Btu). In doing so, they maintain a 34-ng/J standard would encourage baghouses but not eliminate precipitators from use.

EPA has investigated the possibility that FGD control systems affect particulate matter emissions. Three possible mechanisms were investigated: (1) FGD system sulfate carryover from the scrubber slurry, (2) particulate matter removal by the FGD system, and (3) particulate matter generation by the FGD system through condensation of sulfuric acid mist (H_2SO_4).

To address the first mechanism, EPA obtained data from three different steam generators that were all equipped with FGD systems and that had low particulate matter emission levels at the FGD inlet. The data from all three facilities indicated that particulate emissions did not increase through the FGD system. Proper mist eliminator design and maintenance is important in preventing scrubber liquid entrainment which could cause the outlet particulate loading to exceed inlet particulate loading.

In relation to the second mechanism, FGD system removal of particulate matter, the data from the three FGD systems available to EPA indicated that particulate matter emissions were reduced by the FGD systems in all three cases. That is, the particulate matter discharge concentration from the FGD system was less than the concentration at the FGD inlet. This property has been particularly noted at steam generators equipped with ESP's upstream of FGD systems.

The third mechanism is the potential condensation of sulfuric acid mist (H_2SO_4) from sulfur trioxide (SO_3) in the flue gas. At a typical steam generator, 97 to 99 percent of the fuel sulfur is converted to SO_2 and 1 to 3 percent is converted to SO_3. Typical stack gas temperatures at a coal-fired steam generator without an FGD system are between 150° C and 200° C (300° F to 400° F). At these temperatures, most SO_3 remains in a gaseous state and does not form sulfuric acid. At lower temperatures, water vapor condenses and combines with SO_3 to form sulfuric acid. The dewpoint temperature for sulfuric acid ranges between 120° C (250° F) and 175° C (350° F). The lower temperature would correspond to low-sulfur coal and higher temperature would correspond to high-sulfur coal.

Available test data indicate that an FGD system would remove about 50 percent of the SO_3 in the flue gas and thus reduce the potential for sulfuric acid mist formation. However, if sulfuric acid mist is formed in the flue gases, there is a potential for its interference with the particulate matter performance test. Under method 5, a sample is extracted at a probe temperature of about 160° C (320° F). This assures that SO_3 does not condense on the sampling filter when sampling powerplants that do not have FGD systems. However, when sampling powerplants with FGD systems (particularly when combusting high-sulfur coal), there is a potential for sulfuric acid mist to form at the reduced flue gas temperatures. If acid mist forms, it may interact within the sampling train to form sulfate compounds that are not vaporized at the 160° C (320° F) sampling temperature. Also, sulfuric acid mist may remain deposited within the test probe itself. In either case, the net result could be a high measurement of particulate matter.

EPA obtained data from three FGD equipped powerplants to determine acid mist formation potential. All of these plants were firing low-sulfur coal. The data indicate that SO_3 conversion to sulfuric acid mist is not a problem. EPA believes these data support the conclusion that an FGD system on low-sulfur coal-fired powerplants does not increase particulate emissions through sulfuric acid formation. Thus, EPA believes compliance with the proposed particulate matter standard is demonstrated to be achievable when firing low-sulfur coal.

In a case where an FGD system is used with higher sulfur coal, sufficient data have not become available to fully assess the effect of sulfuric acid formation on measured particulate matter. The proposed standard is based on emission test data at the particulate matter control device discharge prior to any FGD system. EPA plans to continue investigating this subject and will consider any data availabale on the impact of sulfuric acid mist on the particulate matter standard.

The 1977 amendments require that EPA specify, in addition to an emission limitation, a percent reduction in uncontrolled emission levels for fossil fuel-fired stationary sources. The proposed standard would require a 99-percent reduction for solid fuels and a 70-percent reduction for liquid fuels. Because of the difficulty of sampling particulate matter upstream of the control device (due to the complex particulate matter sampling conditions), the proposed standard would not require direct performance testing for the particulate matter emission reduction level. The percent reduction is not controlling, and performance testing for the emission limitation would satisfy the requirements for performance testing.

EPA is requesting comments on the proposed level of the particulate matter standard and the basis for the standard.

NO_x

The proposed NO_x emission standards are based on emission levels achievable with a properly designed and operated steam generator which utilizes combustion modification techniques to reduce NO_x formation. The proposed standards are as follows:

(1) 86 ng/J heat input (0.20 lb/million Btu) from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J heat input (0.30 lb/million Btu) from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J heat input (0.50 lb/million Btu) from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;

(4) 340 ng/J (0.80 lb/million Btu) from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;

(5) Combustion of a fuel containing more than 25 percent, by weight, coal refuse would be exempt from the NO_x standards and monitoring requirements;

(6) 260 ng/J (0.60 lb/million Btu) from the combustion of any solid fuel not specified under (3), (4), or (5);

(7) Percent reductions in uncontrolled NO_x emission levels would be required; however, the percent reduction would not be controlling, and compliance with the NO_x emission limits (ng/J) would assure compliance with the percent reduction requirements. the National Appeals Board

Most new electric utility steam generating untis are expected to burn pulverized coal. Consequently, the NO_x studies used to develop the proposed standards have concentrated on the combustion of pulverized coal. The proposed standards for pulverized coal are based on the application of combustion modification techniques (i.e., staged combustion, low excess air, and reduced heat release rate) which EPA has concluded represent the best demonstrated system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements) for electric utility power plants.

The proposed standards would require continuous compliance (based on a 24-hour average), except during periods of startup, shutdown, or malfunction as provided under 40 CFR 60.8. Percent reduction requirements are included in the proposed standards as a result of provisions in the 1977 Amendments. As with the proposed particulate matter standard, the percent reductions for NO_x are not controlling, and compliance testing for the NO_x emission limitations (ng/J) would satisfy all compliance testing requirements for NO_x.

Combustion modification techniques limit the formation of NO_x in the boiler by reducing flame temperatures and by minimizing the availability of oxygen during combustion. Elevated temperatures and high oxygen levels would otherwise enhance the formation of NO_x. The levels to which NO_x emissions can be reduced with combustion modifications depend on the type of fuel burned, the boiler design, and boiler operating practices. All four of the major boiler manufacturers utilize combustion modification techniques in their modern units; however, some manufacturers' techniques may be more effective than others.

EPA has conducted NO_x emmission tests at six modern electric utility steam generating units which burn pulverized coal, representing two of the major boiler manufacturers. These tests indicate that during low NO_x operation of modern units, emission levels below 210 ng/J heat input (0.50 lb/million Btu) are easily attainable. If the potential side effects associated with low NO_x operation were not considered, it would be reasonable to establish an NO_x emission limit for pulverized coal-fired units at 210 ng/J heat input.

The side effects EPA has considered include: Boiler tube wastage (corrosion); slagging; increased emissions of particulates, carbon monoxide, polycyclic organic matter, and other hydrocarbons; boiler efficiency losses; carbon loss in the ash; low steam temperatures; and possible operating hazards (including boiler explosions). In EPA's judgment only boiler tube wastage could be a potential problem at NO_x emission levels necessary to meet a standard of 210 ng/J.

Tube wastage is the deterioration of boiler tube surfaces due to the corrosive effects of ash in the presence of a reducing atmosphere. A reducing atomsphere often results from operation of a boiler under conditions required to minimize NO_x emissions. The severity of tube wastage is believed to vary with several factors, but especially with the quality of the coal burned. For example, high sulfur Eastern coal generally causes more of a tube wastage problem than low sulfur Western coal. Serious tube wastage can shorten the life of a boiler and result in expensive repairs.

Because of the potential problem from tube wastage, EPA does not believe that an emission limit below the proposed level of 260 ng/J heat input for Eastern bituminous coals would be reasonable even though emission data alone would tend to support a lower limit. For low rank Western coals, however, there is a much smaller tube wastage potential at low NO_x levels, and a lower emission limit is justified. Hence, EPA is proposing an emission limit of 210 ng/J heat imput for units burning low rank Western coals. These coals are classified in the proposed standards as subbituminous, according to ASTM methods. EPA believes that the proposed distinction made between low rank Western (subbituminous) coal and other coals represents the best method for distinguishing between coals with low and high tube wastage potentials.

Although most new utility power plants will fire pulverized coal, other fuels may also be burned. Emission limits for these fuels are also proposed.

The proposed NO_x emission limits for units which burn liquid and gaseous fuels are at the same levels as the emission limits originally promulgated in 1971 under subpart D for large steam generators which burn oil and gas. EPA did not conduct a detailed study of combustion modification or NO_x flue gas treatment for oil- or gas-fired boilers because few, if any, oil- or gas-fired electric utility power plants are expected to be built in the future.

Several studies have been conducted which indicate that emissions from the combustion of liquid and gaseous fuels which are derived from coal, such as solvent refined coal and low Btu synthetic gas, may exceed the proposed emission limits for liquid fuels (130 ng/J) and gaseous fuels (86 ng/J). The reason is because fuels derived from coal will have fuel bound nitrogen contents which approach the levels found in coal rather than in natural gas and oil. Based on limited emission data from pilot-scale facilities and on the known emission characteristics of coal, EPA believes that an achievable emission limit for solid, liquid, of gaseous fuels derived from coal would be 210 ng/J (0.50 lb/million Btu). Tube wastage of other boiler problems are not expected to occur from boiler operation at levels as low as 210 ng/J when firing these fuels because of their low sulfur and ash contents.

Very little is known about the emission characteristics of shale oil. However, since shale oil typically has a higher fuel-bound nitrogen content than fuel oil, it may be impossible for a well-controlled unit burning shale oil to achieve the proposed NO_x emission limit for liquid fuels. Shale oil does have a similar nitrogen content to coal, and it is reasonable to expect that the emission control techniques used for coal could also be used to limit NO_x emissions from shale oil combustion. Consequently, EPA proposes to limit NO_x emissions from units burning shale oil to 210 ng/J, the same limit proposed for subbituminous coal. There is no evidence that tube wastage or other boiler problems would result from operation of a boiler at 210 ng/J when shale oil is burned.

The combustion of coal refuse was exempted from the subpart D standards because the only furnace design believed capable of burning coal refuse, the slag tap furnace, inherently produces NO_x emissions in excess of the NO_x standard. Since no new information has become available, EPA would continue the coal refuse exemption under the proposed standards.

The proposed emission limits for lignite combustion were developed earlier as amendments to the original standards under subpart D. Since no new information on NO_x emission rates resulting from lignite combustion in electric utility power plants has become available, the lignite limits have been incorporated into these proposed standards without revision.

While EPA believes that the proposed emission limitations for bituminous and subbituminous coals can be achieved without adverse effects, UARG recommends that the present NO_x emission limitation of 300 ng/J (0.7 lb/million Btu) be retained. In so doing, they argue that the potential adverse side effects that may result from operating a boiler under conditions required to meet the proposed standards have not been adequately studied over the long term. They also expressed concern that the proposed standards could have an anticompetitive effect, since they believe there may be only one boiler vendor who could meet the proposed standards on a continuous basis. Finally, they question whether there is sufficient continuous monitoring experience to warrant basing compliance on continuous monitoring results.

STUDIES

The background information including environmental and economic assessments for the proposed standards is divided into 4 documents, each with a title and a document number as follows:

"Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards." EPA 450/2-78-006a;

"Electric Utility Steam Generating Units: Background Information for proposed Particulate Matter Emission Standards," EPA 450/2-78-006a;

"Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards." EPA 450/2-78-007a; and

"Electric Utility Steam Generating Units: Background Information for Proposed SO_2

Emission Standards—Supplement," EPA 450/2-78-007a-1.

Much of the supporting information within the background information documents was obtained from consultant studies sponsored by EPA. Reports covering these studies are included in the docket at EPA headquarters and are available for inspection during normal office hours at each EPA regional office. The titles of the consultant studies are as follows:

1. "Flue Gas Desulfurization Systems: Design and Operating Parameters, SO_2 Removal Capabilities, Coal Properties and Reheat."
2. "Flue Gas Desulfurization System Capabilities for Coal-Fired Steam Generators."
3. "Boiler Design and Operating Variables Affecting Uncontrolled Sulfur Emissions from Pulverized Coal-Fired Steam Generators."
4. "Effects of Alternative New Source Performance Standards on Flue Gas Desulfurization System Supply and Demand."
5. "Evaluation of Physical Coal Cleaning as an SO_2 Emission Control Technique."
6. "The Impact of Modification/Reconstruction of Steam Generators on SO_2 Emissions."
7. "The Energy Requirements for Controlling SO_2 Emissions from Coal-Fired Steam/Electric Generators."
8. "The Solid Waste Impact of Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators."
9. "Water Pollution Impact of Controlling SO_2 Emissions from Coal-Fired Steam/Electric Generators."
10. "Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers."
11. "Review of New Source Performance Standards for SO_2 Emissions from Coal-Fired Utility Boilers."
12. "The Effect of Flue Gas Desulfurization Availability on Electric Utilities."
13. "Effects of Alternative New Source Performance Standards for Coal-Fired Electric Utility Boilers on the Coal Markets and Utility Capacity Expansion Plans."
14. "Flue Gas Desulfurization System Manufacturers Survey."
15. "Assesement of Manufacturer Capacity to Meet Requirements for Particulate Control in Utility and Industrial Boilers."
16. "Flue Gas Desulfurization Cost for Large Coal-Fired Boilers, August 10, 1978."
17. "The Ability of Electric Utilities with FGD to Meet Energy Demands."

In addition to the consultant studies, EPA studies were performed. One study involved the installation and operation of continuous SO_2 monitors on the inlet and outlet of commercial-scale FGD units. The purposes of the study were to determine: (1) The statistical characteristics of coal-fired boiler and FGD operation, (2) the variability of SO_2 inlet concentrations, (3) the ability of FGD to "damp out" SO_2 variability, and (4) SO_2 emissions as a function of averaging period.

A second EPA study included a diffusion modeling analysis to estimate the maximum ground-level concentration of SO_2 that would occur around small, medium, and large power plants for emission rates with and without flue gas reheat. The study also examined the estimated SO_2 concentrations that would occur around multi-boiler facilities. Surface and upper-air meteorological data for eight different geographical areas were used in the study.

EPA has also supplemented the economic, energy, and environmental impact assessment set forth in the background information document for the SO_2 standard (EPA 450/2-78-007a) by conducting two additional analyses. The first was initiated in February 1978, and results became available in late April. The second, which was completed in August, used revised assumptions pertaining to utility growth rates, oil prices, etc. The results of these studies are presented in sections 2 and 3 of the "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards—Supplement," EPA 450/2-78-007a-1.

EPA has also taken into consideration studies prepared by other Governmental Agencies. One study is "The Demand for Western Coal and its Sensitivity to Key Uncertainties," draft report, 2nd edition, June 1978, which assessed the potential impact of this proposal on coal demand. This report was prepared by a consultant for the Department of Interior and the Department of Energy. In addition the analysis of alternative standards prepared by the Department of Energy, and transmitted to EPA by Mr. John F. O'Leary, Deputy Secretary, on July 6 and August 11, 1978, was also considered.

A task force of American experts in scrubber technology visited Japan to evaluate Japanese scrubber performance. The findings (Maxwell, Elder and Morasky, "Sulfur Oxides Control Technology in Japan," June 30, 1978) were also considered by EPA.

PERFORMANCE TESTING

PARTICULATE STANDARDS

Compliance with the proposed particulate matter standards would be determined by using EPA method 5 operated at a filter temperature up to 160°C (320°F). As an option, EPA method 17 may be used for stack gas temperature less than 160°C. EPA method 3 would be used to determine oxygen or carbon dioxide concentrations. These concentration measurements would then be used to compute particulate emissions in units of the standard as specified in proposed EPA method 19.

Compliance with opacity standards could be determined at any time by visual observations using EPA method 9. Except during startups, shutdowns, and malfunctions, all data from visual observations would be ued for determining compliance with the proposed opacity standard.

A continuous monitoring system for opacity would be required in the stack except when firing only gaseous fuels. The opacity data from the continuous monitor would not be used to determine compliance with the opacity standard. It would be used to assist in assuring the particulate matter control system is properly operated and maintained.

SO_2 AND NO_x STANDARDS

Performance tests. Compliance with the proposed SO_2 and NO_x standards would be determined using the data obtained from the required continuous monitoring systems. If an FGD system were used for SO_2 control, continuous SO_2 emission monitors would be required both upstream and downstream of the FGD system and used to determine compliance with the proposed 85 percent SO_2 reduction. As an option, compliance with the proposed SO_2 standards could be determined using both an "as fired" fuel sampler to determine the sulfur content and heating value of the fuel fired to the boiler, and a continuous SO_2 emission monitor after the FGD system to measure SO_2 emissions discharged into the atmosphere. In addition to crediting the SO_2 removed by the FGD system, this option would provide credit for sulfur removed by coal pulverizers and by the bottom ash and fly ash. The SO_2 percent reduction requirement and emission limitation would both be based on emission levels averaged over a 24-hour (daily) period. If fuel is treated prior to combustion to reduce SO_2 emissions, a sulfur removal credit would also be allowed. Procedures for determining sulfur removal credits are proposed under § 60.48a with EPA method 19.

Performance testing to determine compliance with the NO_x emission limitation (ng/J) would be determined on a continuous basis through the use of a continuous NO_x emission monitor. NO_x emission data would be averaged over a 24-hour (daily) period. Performance testing to determine compliance with the percent reduction requirements for NO_x would not be required. An affected facility would be assumed to be in compliance with the NO_x reduction requirements provided the facility is in compliance with the applicable NO_x emission limitation.

When the NO_x or SO_2 continuous monitoring system fails to operate properly, the source owner or operator would obtain emission data by:

1. Operation of a second monitoring system, or
2. Conducting manual tests using EPA reference methods during the period the continuous monitoring system is inoperative.

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Operation of a second monitoring system would mean that the source owner would have a second system in operation at all times. Conducting the manual tests would mean that the source owner would have trained manpower available on an immediate basis to collect samples while the continuous monitoring system is inoperative. Manual test runs would be required on an hourly basis.

Since compliance with the proposed SO_2 and NO_x standards would be determined by continuous monitors, EPA is currently developing additional quality assurance procedures. These procedures would not change the present performance specifications for continuous monitoring systems, but would provide additional periodic field tests to assure the accuracy of the monitoring data. Appendix E under 40 CFR Part 60 is being reserved for these additional quality assurance procedures. Electric utility powerplants that would be subject to the proposed standard would be subject to the quality assurance procedures under appendix E when completed. This should not pose a problem since new sources affected by this proposed action are not expected to begin operation until about 1984.

Fuel pretreatment. Pretreatment of a fuel to remove sulfur or increase heat content would be credited toward the SO_2 percent reduction requirement. For example, by pretreatment of a 2.3 percent sulfur fuel (equivalent to 1,000 ng/J) to 1.7 percent sulfur (750 ng/J; 25 percent sulfur removal), the FGD system SO_2 control requirement would be reduced from 85 percent to 80 percent (750 ng/J reduced to 150 ng/J). An 85 percent emission reduction (1,000 ng/J to 150 ng/J) would be necessary for an FGD system if the fuel were fired untreated.

Fuel pretreatment credits would be given for removal of sulfur from fuel, including the resulting increase in fuel heat content. Examples of the type of equipment or processes for which credit would be given are:

1. Physical coal cleaning.
2. Solvent refining of coal.
3. Liquification of coal.
4. Gasification of coal.

Rotary breakers or coarse screens used to separate rock and other material from raw coal prior to processing or shipment are considered an integral part of the coal mining process and would not be considered as fuel pretreatment (see section 4.5.2.2 of EPA 450/2-78-007a-1).

The proposed standard would not require fuel to be pretreated before firing but would allow credit for pretreatment if used. The amount of sulfur removed by a fuel pretreatment process would be determined following procedures in EPA method 19 (appendix A). The owner or operator of the electric utility who would use the credit would be responsible for insuring that the EPA method 19 procedures are followed in determining SO_2 removal credit for pretreatment equipment.

MISCELLANEOUS

As prescribed by section 111, establishment of standards of performance for electric utility steam generating units was preceded by the Administrator's determination that these sources contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare. In accordance with section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues, and on the proposed test methods.

Under EPA's "new" sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire 5 years from the date of promulgation unless EPA takes affirmative action to extend them. To accomplish this, a provision automatically terminating the reporting requirements at that time will be included in the text of the final regulations.

It should be noted that standards of performance for new fossil fuel fired stationary sources established under section 111 of the Clean Air Act reflect:

> * * * application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. [Section 111(a)(1)]

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas, i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, section 173 of the act requires that a new or modified source constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such category of source. The statute defines LAER as that rate of emission which reflects:

> (A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) The most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

In no event can the emission rate exceed any applicable new source performance standard (section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (part C). These provisions require that certain sources (referred to in section 169(1)) employ "best available control technology" (as defined in section 169(3)) for all pollutants regulated under the Act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State implementation plans (SIPs) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of national Ambient Air Quality Standards designed to protect public health and welfare. For this purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

EPA will review this regulation 4 years from the date of promulgation. this review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emission control technology.

Executive Order 12044, dated March 24, 1978, whose objective is to improve Government regulations, requires executive branch agencies to prepare regulatory analyses for regulations that may have major economic consequences. The proosed standards meet the criteria for preparation of a regulatory analysis as outlined in the Executive order. Therefore, a regulatory analysis has been prepared as required. The analysis is contained in the background information documents for the proposed standards. The regulatory analysis is not being published as a separate document because the work was begun before the President's Executive order was published. However, in order to present a better understanding of the analyses contained in the background information documents, a summary of the analyses is included in the preamble. The summary discusses in detail the alternatives considered.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for revisions determined by the Administrator to be substantial. The Administrator has determined that the proposed amendments are substantial and has prepared an economic impact assessment and included the required information in thebackground information documents.

Dated: September 11, 1978.

Douglas M. Costle,
Administrator.

It is proposed that 40 CFR Part 60 be amended by revising the heading and § 60.40 of Subpart D, by adding a new Subpart Da, by adding a new reference method to Appendix A, and by reserving Appendix E as follows:

1. The heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators Constructed After August 17, 1971

2. Section 60.40 is amended by adding paragraph (a)(3) as follows:

§ 60.40 Applicability and designation of affected facility.

(a) * * *

(3) Is not subject to the provisions of Subpart Da.

* * * * *

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)).)

3. A new Subpart Da is added as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Sec.
60.40a Applicability and designation of affected facility.
60.41a Definitions.
60.42a Standard for particulate matter.
60.43a Standard for sulfur dioxide.
60.44a Standard for nitrogen oxides.
60.45a Commercial demonstration permit.
60.46a Compliance provisions.
60.47a Emission monitoring.
60.48a Compliance determination procedures and methods.
60.49a Reporting requirements.

Authority: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Contruction Is Commenced After September 18, 1978

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) Which is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fossil fuel in the steam generator are subject to this subpart. (The gas turbine emissions are subject to Subpart GG.)

§ 60.41a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). A steam generating unit includes the following systems:

(1) Fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable).

(2) Combustion air system.

(3) Steam generating system (firebox, boiler tubes, etc.).

(4) Draft system (excluding the stack).

(b) "Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its maximum design electrical output capacity to an electrical distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

(c) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

(d) "Subbituminous coal" means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

(e) "Lignite" means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

(f) "Coal refuse" means waste products from coal mining, physical coal cleaning, and coal refining operations (e.g. culm, gob, or other rejects) containing coal, ash matrix material, clay, and organic and inorganic material.

(g) "Potential combustion concentration" means the theoretical emissions (ng/J, lb/million Btu) that would result from combustion of a fuel in an uncleaned state (without emission control systems) and:

(1) For particulate matter is:

(i) 3,000 ng/J heat input (7.0 lb/million Btu) for solid fuel; and

(ii) 75 ng/J heat input (0.17 lb/million Btu) for liquid fuels.

(2) For sulfur dioxide is determined under § 60.48a(b).

(3) For nitrogen oxides is:

(i) 290 ng/J heat input (0.67 lb/million Btu) for gaseous fuels;

(ii) 310 ng/J heat input (0.72 lb/million Btu) for liquid fuels; and

(iii) 990 ng/J heat input (2.3 lb/million Btu) for solid fuels.

(h) "Combined cycle gas turbine" means a stationary gas turbine system where heat is recovered from the exhaust gases by passing the exhaust gases through a steam generating unit. fossil fuel may also be combusted in the steam generating unit.

(i) "Utility company" means the largest organization, business, or governmental entity that owns the affected facility (e.g. a holding company with operating subsidiary companies).

(j) "System capacity" means the sum of the rated electrical output capacity of all electric generating equipment which is owned by the utility company and which is being operated or is capable of being operated (including fossil-fuel-fired steam generators, internal combustion engines, gas turbines, and nuclear power plants). The electrical generating capacity of electric generating equipment under multiple ownership is prorated based on ownership.

(k) "System emergency reserves" means the rated capacity of the single largest steam electric generating unit (including fossil-fuel-fired steam generators, internal combustion engines, gas turbines, and nuclear power plants) owned by the utility company. The electric generating capacity of electric generation equipment under multiple ownership is prorated based on ownership.

(l) "Available system capacity" means the capacity determined by subtracting the system load and the system emergency reserves from the system capacity.

(m) "Spinning reserve" means the sum of the unutilized capacity of all units of the utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electrical generating capacity of electric generation equipment under multiple ownership is prorated based on ownership.

(n) "Emergency condition" means that period of time:

(1) When the electric generation load on an affected facility with a malfunctioning flue gas desulfurization system cannot be shifted because all available system capacity is being operated, or

(2) When all available system capacity is not being utilized and electric generation load is being shifted as quickly as possible from the affected facility to:

(i) One or more electric generating units held in spinning reserve, or

(ii) Another electrical generation system through the purchase of electric power.

(o) "Noncontinental areas" means the State of Hawaii, the Virgin Islands, Guam, American Samoa, and the Commonwealths of Puerto Rico and the Northern Mariana Islands.

(p) "Commercial demonstration plant" means:

(1) An affected facility commercially demonstrating an emerging technology, or

(2) Any of the affected facilities that combust the coal-derived fuel produced at a commercial demonstration coal conversion plant, demonstrating an emerging technology.

(q) "24-hour period" means the period of time between 12:01 a.m. and 12:00 midnight.

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:

(1) 13 ng/J heat input (0.03 lb/million Btu) derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity, except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.43a Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

(1) 340 ng/J heat input (0.80 lb/million Btu) derived from the combustion of any liquid or gaseous fuel;

(2) 520 ng/J heat input (1.2 lb/million Btu) derived from the combustion of any solid fuel except as provided under paragraph (b) of this section; and

(3) 15 percent of the potential combustion concentration (85 percent reduction) when combusting solid, liquid, or gaseous fuel, except as provided under paragraphs (b) and (c) of this section.

(b) The sulfur dioxide emissions allowed under paragraph (a) of this section may be exceeded up to three 24-hour periods during any calendar month, however, the sulfur dioxide emissions must be reduced to less than 25 percent of the potential combustion concentration (75 percent reduction) at all times.

(c) The requirements under paragraph (a)(3) of this section do not apply when any of the following conditions are met:

(1) The sulfur dioxide emitted to the atmosphere is less than 86 ng/J heat input (0.20 lb/million Btu).

(2) The affected facility is located in a noncontinental area.

(3) The affected facility is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(d) For purposes of determining compliance with provisions of paragraph (a)(3) of this section, any reduction in potential sulfur dioxide emissions resulting from the following may be credited in accordance with § 60.48a(b):

(1) Fuel pretreatment.

(2) Coal pulverizers.

(3) Bottom ash and fly ash interaction.

(e) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$PS_{SO_2} = x(340) + y(520)/100$$

where:

PS_{SO_2} is the prorated standard for sulfur dioxide when combusting different fuels simultaneously (ng/J heat input).

x is the percentage of total heat input derived from the combustion of gaseous and liquid fuel.

y is the percentage of total heat input derived from the combustion of solid fuel.

§ 60.44a Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides in excess of:

(1) 86 ng/J heat input (0.20 lb/million Btu) derived from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J heat input (0.30 lb/million Btu) derived from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J heat input (0.50 lb/million Btu) derived from the combustion of:

(i) Subbituminous coal,

(ii) Shale oil, or

(iii) Any solid, liquid, or gaseous fuel derived from coal; except as provided under paragraph (c) of this section.

(4) 260 ng/J heat input (0.60 lb/million Btu) derived from the combustion of any solid fuel not specified under paragraphs (a)(3), (a)(5) or (b) of this section;

(5) 340 ng/J heat input (0.80 lb/million Btu) derived from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;

(6) 75 percent of the potential combustion concentration (25 percent re-

duction) when combusting gaseous fuel;

(7) 70 percent of the potential combustion concentration (30 percent reduction) when combusting liquid fuel; and

(8) 35 percent of the potential combustion concentration (65 percent reduction) when combusting solid fuel.

(b) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from both the provisions of § 60.47a(a)(3) and paragraph (a) of this section.

(c) The requirements under paragraph (a) of this section do not apply when an affected facility is operated under an NO_x commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(d) When two or more fuels, except as provided under paragraphs (a)(5) or (b) of this section, are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$PS_{NO_x}\, w(86)+x(130)+y(210)+z(260)/100$$

where:

PS_{NO_x} is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard; and

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard.

§ 60.45a Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (d) of this section. Commercial demonstration permits may only be issued by the Administrator, and this authority will not be delegated.

(b) An owner or operator who is issued an SO_2 commercial demonstration permit by the Administrator is not subject to the SO_2 control requirements under § 60.43a(a)(3) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent SO_2 control on a 24-hr basis)

(c) An owner or operator who is issued an NO_x commercial demonstration permit by the Administrator is not subject to the NO_x control requirements under § 60.44a but must, as a minimum, reduce NO_x emissions to 300 ng/J heat input (0.70 lb/million Btu; 24-hour average).

(d) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commerical demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent MW electrical capacity
Solvent refined coal (I)	SO_2	6,000-10,000
Fluidized bed combustion (atmospheric).	SO_2	400-3,000
Fluidized bed combustion (pressurized).	SO_2	400-1,200
Coal liquifaction	NO_x	750-10,000
Total allowable for all technologies.		15,000

§ 60.46a Compliance provisions.

(a) Compliance with the particulate matter emission limitation under § 60.42(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under § 60.42a(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under § 60.44a(a)(1), (2), (3), (4), and (5) as applicable, constitutes compliance with the percent reduction requirements under §60.44a(a)(6), (7), and (8).

(c) Following the initial performance tests for sulfur dioxide and nitrogen oxides required under §60.8, each 24-hour period constitutes a separate performance test. The nitrogen oxides emission standards under §60.44a apply at all time except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under §60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.

(d) During emergency conditions an affected facility with a malfunctioning flue gas desulfurization system may continue operation if sulfur dioxide emissions are minimized by:

(1) Continued operation of all operable flue gas desulfurization system modules,

(2) Only by-passing flue gases around totally inoperable flue gas desulfurization system modules, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module in affected facilities larger than 365 MW heat input (1,250 million Btu/hr).

§60.47a Emission monitoring.

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility which qualifies under the provisions of §60.43a(c), sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of method 19 (Appendix A) may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(4) If a facility which complies with §60.43a(a) solely through the provisions under §60.43a(d), then sulfur dioxide emissions are only monitored at the outlet of the sulfur dioxide contol device.

(c) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides emissions discharged to the atmosphere.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate an oxygen or carbon dioxide monitoring system to measure the oxygen or carbon dioxide content of the flue gas at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The owner or operator of an affected facility shall operate continuous emission monitoring systems during all periods except for the following:

(1) A maximum of sixty (60) minutes each day for daily zero and calibration checks or adjustments.

(2) A maximum of eight (8) hours per month for routine maintenance.

(f) During periods of operation of the affected facility when continuous monitoring systems (and spare monitoring systems if used) are not operable, the owner or operator of the affected facility shall conduct performance tests consisting of manual testing each hour until the continuous monitor system is returned to service. Each hourly test is performed as follows:

(1) Reference methods 3, 6, and 7, as applicable, are used. The sampling location(s) are the same as those used for the continuous monitoring system.

(2) For method 6, the minimum sampling time shall be 20 minutes and the minimum sampling volume 0.02 dscm (0.71 dscf) for each sample. The arithmetic mean of two samples taken at approximately 30-minute intervals constitutes one run. The arithmetic mean of the runs obtained during a 24-hour period is reported as the average for that period. For determination of FGD removal efficiency, inlet and outlet sampling is conducted simultaneously.

(3) For method 7, each run consists of at least four grab samples taken at approximately 15-minute intervals. The arithmetic mean of the four samples constitutes the 1-hour run. The arithmetic mean of the runs obtained during a 24-hour period is reported as the average for that period.

(4) For method 3, the oxygen or carbon dioxide sample is obtained simultaneously at the same location in the duct as the samples collected using methods 6 and 7. For method 7, the oxygen sample is obtained using the grap sampling and analysis procedures of method 3.

(5) For each run using method 19 in appendix A to this part, the emissions expressed in ng/J (lb/million Btu) are determined. The arithmetic mean of the runs performed during a 24-hour period is reported as the average for that period.

(g) The following procedures are used for monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d):

(1) Reference method 6 or 7, as applicable, is used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.

(2) Sulfur dioxide or nitrogen oxides, as applicable, is used for preparing calibration gas mixtures under performance specification 2 of appendix B to this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

[Parts per million]

Fossil fuel	Span value for nitrogen oxides
Gas	500
Liquid	500
Solid	1,000
Combinations	500 $(x+y)+1{,}000z$

where:

x = the fraction of total heat input derived from gaseous fossil fuel,

y = the fraction total heat input derived from liquid fossil fuel, and

z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur-dioxide continuous monitoring system at the inlet to the sulfur-dioxide-control device is 200 percent of the potential emissions of the fuel fired, and at the outlet of the sulfur-dioxide-control device is 50 percent of potential emissions. When the percent fuel sulfur content changes by 0.5 (24-hour average) or more, the continuous monitoring system shall be respanned.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.48a Compliance determination procedures and methods.

(a) The following procedures and reference methods are used to determine compliance with the standards for particulate matter under § 60.42a:

(1) Method 3 is used for gas analysis when applying method 5 or method 17.

(2) Method 5 is used for determining particulate matter emissions and associated moisture content. Method 17 may be used for stack gas temperatures less than 160° C (320° F).

(3) For method 5 or method 17, method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(4) For method 5, the probe and filter holder heating system in the sampling train is set to provide a gas temperature no greater than 160° C (320° F).

(5) For determination of particulate emissions, the oxygen or carbon-dioxide sample is obtained simultaneously with each run of method 5 or method 17 by traversing the duct at the same sampling location. Method 1 is used for selection of the number of traverse points except that no more than 12 sample points are required.

(6) For each run using method 5 or method 17, the emission rate expressed in ng/J is determined using the oxygen or carbon-dioxide results and particulate results obtained under this section, and using the dry F-factor and dry basis emission rate calculation procedure contained in method 19 (appendix A).

(b) The following procedures and methods are used to determine compliance with the sulfur dioxide standard under § 60.43a:

(1) Determine the percent of potential combustion concentration (percent PCC) emitted to the atmosphere as follows:

(i) Determine the percent sulfur reduction achieved by any fuel pretreatment using the procedures in method 19 (appendix A; optional procedure). Calculate the average percent reduction on a quarterly basis using fuel analysis data.

(ii) Determine the percent sulfur dioxide reduction achieved by any sulfur dioxide control system using continuous sulfur dioxide emission monitors or an "as fired" fuel monitor (optional procedure) in conjunction with a continuous sulfur-dioxide-emission monitor and following the procedures in method 19 (appendix A). If 24 hours of data are not available (such as during startup or shutdown), all available valid data are averaged for each 24-hour period.

(iii) Determine atmospheric sulfur dioxide emissions as a percent of the potential combustion concentration (percent PCC) as follows: Use the results obtained in paragraphs (b)(1) (i) (optional) and (ii) of this section and the procedures in method 19 (appendix A) to calculate the overall percent reduction (percent R_o) of the potential sulfur dioxide emissions. Results are calculated for each 24-hour period using the quarterly average percent sulfur reduction determined for fuel pretreatment from the previous quarter and the sulfur dioxide reduction for each 24-hour period determined for each day in the current quarter. Calculate the percent of potential combustion concentration emitted to the atmosphere using the following equation:

$$\text{Percent PCC} = 100 - \text{percent } R_o$$

(2) Determine sulfur dioxide and nitrogen oxides emission rates using method 19 (appendix A). Emission rates are calculated for each 24-hour period and shall be considered to constitute a three-run performance test. If 24 hours of data are not available in a 24-hour period (such as during startup or shutdown), all available valid data for the period are averaged.

(c) The procedures and methods outlined in method 19 (appendix A) are used in conjunction with the 24-hour nitrogen-oxides emission data collected under § 60.47a to determine compliance with the applicable nitrogen oxides standard under § 60.44a.

(d) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of method 19 (appendix A). The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in method 19 (appendix A) calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.49a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of continuous monitors are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides, all emission data (24-hour daily average) collected subsequent to the initial performance test are submitted to the Administrator. The required data include the following information for each 24-hour period:

(1) Calendar date;

(2) Sulfur dioxide and nitrogen oxides emission rates (ng/J or lb/million Btu, 24-hour average);

(3) Percent reduction of the potential combustion concentration of sulfur dioxide (24-hour average) (not required for nitrogen oxides);

(4) Number of hours of valid emission data collected during each 24-hour daily period;

(5) Identification of periods when emissions exceed the applicable standards under either § 60.43a or § 60.44a;

(6) Identification of periods of startup or shutdown that resulted in emissions exceeding the applicable standards under either § 60.43a or § 60.44a;

(7) Identification of periods when control system malfunction resulted in emissions in excess of applicable nitrogen oxides standards under § 60.44a;

(8) Identification of "F" factor used for calculations, and type of fuel combusted; and

(9) Identification of periods when any continuous monitoring systems are not operating and identification of pollutant to be monitored.

(c) If any standards under § 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if conditions of §§ 60.41a(n) and 60.46a(d) were met during each period; and

(2) Listing the:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner's or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from the interconnected reliability council during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system modification.

(d) If fuel pretreatment credit toward the sulfur dioxide emission standard under § 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of § 60.48a and method 19 (appendix A); and

(2) Listing the quantity heat content and date each pretreated fuel shipment was received during the previous quarter, the name and location of the fuel pretreament facility, and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(e) For the purposes of the reports required under § 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standard under § 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are submitted to the Administrator each calendar quarter.

(f) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

4. Appendix A to part 60 is amended by adding new reference method 19 as follows:

APPENDIX A—REFERENCE METHODS

* * * * *

METHOD 19. DETERMINATION OF SULFUR-DIOXIDE REMOVAL EFFICIENCY AND PARTICULATE, SULFUR DIOXIDE AND NITROGEN OXIDES EMISSION RATES FROM ELECTRIC UTILITY STEAM GENERATORS

1. Principle and applicability.

1.1 Principle.

1.1.1 Fuel samples from before and after fuel pretreatment systems are collected and analyzed for sulfur and heat content, and the percent sulfur dioxide (ng/Joule, lb/million Btu) reduction is calculated on a dry basis. (Optional procedure.)

1.1.2 Sulfur dioxide and oxygen or carbon dioxide concentration data obtained from sampling emissions upstream and downstream of sulfur-dioxide-control devices are used to calculate sulfur-dioxide removal efficiencies. (Minimum requirement.) As an alternative to sulfur-dioxide monitoring upstream of sulfur-dioxide-control devices, fuel samples may be collected in an as-fired condition and analyzed for sulfur and heat content. (Optional procedure.)

1.1.3 An overall sulfur dioxide emission reduction efficency is calculated from the efficiency of fuel pretreatment systems and the efficiency of sulfur dioxide control devices.

1.1.4 Particulate, sulfur dioxide, nitrogen oxides, and oxygen or carbon dioxide concentration data obtained from sampling emissions downstream from sulfur dioxide control devices are used along with F factors to calculate particulate, sulfur dioxide, and nitrogen-oxides emission rates. F factors are values relating combustion gas volume to the heat content of fuels.

1.2 Applicability. This method is applicable for determining sulfur removal efficiencies of fuel pretreatment and sulfur-dioxide-control devices and the overall reduction of potential sulfur dioxide emissions from electric utility steam generators. This method is also applicable for the determination of particulate, sulfur dioxide, and nitrogen oxides emission rates.

2. *Determination of sulfur-dioxide removal efficiency of fuel pretreatment systems* (optional).

2.1 Solid fossil fuel.

2.1.1 Sample increment collection. Use ASTM D 2234,* type I, conditions A, B, or C, and systematic spacing. Determine the number and weight of increments required per gross sample representing each coal lot according to table 2 or paragraph 7.1.5.2 of ASTM D 2234.* Collect one gross sample for each raw coal lot and one gross sample for each product coal lot.

2.1.2 ASTM lot size. For the purpose of section 2.1.1, the product coal lot size is defined as the weight of product coal produced from one type of raw coal. The raw coal lot size is the weight of raw coal used to produce one product coal lot. Typically, the lot size is the weight of coal processed in a 1-day (24 hours) period. If more than one type of coal is treated and produced in 1 day, then gross samples must be collected and analyzed for each type of coal. A coal lot size equaling the 90-day quarterly fuel quantity for a specific powerplant may be used if representative sampling can be conducted for the raw coal and product coal.

NOTE.—Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

2.1.3 Gross sample analysis. Determine the percent sulfur content (percent S) and gross calorific value (GCV) of the solid fuel on a dry basis for each gross sample. Use ASTM 2013* for sample preparation, ASTM D 3177* for sulfur analysis, and ASTM D 3173* for moisture analysis. Use ASTM D 3176* or D 2015* for gross calorific value determination.

2.2 Liquid fossil fuel.

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*Use the most recent revision or designation of the ASTM procedure specified.

2.2.1 Sample collection. Use ASTM D 270* following the practices outlines for continuous sampling for each gross sample representing each fuel lot.

2.2.2 Lot size. For the purposes of section 2.2.1, the weight of product fuel from one pretreatment facility and intended as one shipment (shipload, bargeload, etc.) is defined as one product fuel lot. The weight of each crude liquid fuel type used to produce one product fuel lot is defined as one inlet fuel lot.

NOTE.—Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

2.2.3 Sample analysis. Determine the percent sulfur content (percent S) and gross calorific value (GVC). Use ASTM D 240* for the sample analysis. This value can be assumed to be on a dry basis.

2.3 Calculation of sulfur-dioxide removal efficency due to fuel pretreatment. Calculate the percent sulfur dioxide reduction due to fuel pretreatment using the following equation:

$$\%R_f = 100\left[1 - \frac{\%S_o/GCV_o}{\%S_i/GCV_i}\right]$$

Where:

$\%R_f$=Sulfur dioxide removal efficiency due pretreatment; percent.
$\%S_o$=Sulfur content of the product fuel lot on a dry basis; weight percent.
$\%S_i$=Sulfur dioxide content of the inlet fuel lot on a dry basis; weight percent.
GCV_o=Gross calorific value for the outlet fuel lot on a dry basis; kJ/kg (Btu/lb).
GCV_i=Gross calorific value for the inlet fuel lot on a dry basis; kJ/kg (Btu/lb).

NOTE.—If more than one fuel type is used to produce the product fuel, use the following equation to calculate the sulfur content per unit of heat content of the total fuel lot, %S/GCV:

$$\%S/GCV = \sum_{k=1}^{n} Y_k\ (\%S_k/GCV_k)$$

Where:

Y_k=The fraction of total mass input derived from each type, k, of fuel.
$\%S_k$=Sulfur content of each fuel type, k, on a dry basis; weight percent.
GCV_k=Gross calorific value for each fuel type, k, on a dry basis; kJ/kg (Btu/lb).
n=The number of different types of fuels.

3. *Determination of sulfur removal efficiency of the sulfur dioxide control device.*

3.1 Sampling. Determine SO_2 and CO_2 or O_2 oxygen concentrations at the inlet and outlet of the sulfur dioxide control system according to methods specified in the applicable subpart of the regulations.

(NOTE.—The downstream data are used to calculate the SO_2 emission rate. See section 5.) The inlet sulfur dioxide concentration may be determined through fuel analysis (optional, see section 3.3).

3.2 Calculation. Calculate the percent removal efficiency using the following equations as applicable:

$$\%R_{g(O_2)} = 100\left[1 - \frac{SO_{2do}}{SO_{2di}}\left(\frac{20.9 - \%O_{2di}}{20.9 - \%O_{2do}}\right)\right]$$

$$\%R_{g(CO_2)} = 100\left[1 - \left(\frac{SO_{2do}}{SO_{2di}} \times \frac{\%CO_{2di}}{\%CO_{2do}}\right)\right]$$

Where:

$\%R_g(O_2)$=Sulfur dioxide removal efficiency of the sulfur dioxide control device, O_2-based calculation; percent.
$\%R_g(CO_2)$=Sulfur dioxide removal efficiency of the sulfur dioxide control device, CO_2-based calculation; percent.
SO_{2d}=SO_2 concentration, dry basis; ppmv.
$\%CO_{2d}$=$C0_2$concentration, dry basis; bolume percent.
$\%O_{2d}$=CO_2 concentration, dry basis; volume percent.
i=Inlet.
o=Outlet.

NOTE.—For devices measuring concentration on a wet basis, appropriate equations which account for moisture differences are approved in principle. See the appropriate paragraph in section 5.3. Methods for measuring moisture content are subject to approval of the Administrator.

3.3 As-fired fuel analysis (optional procedure). If the owner or operator of an electric utility steam generator chooses to determine the sulfur dioxide input rate at the inlet to the sulfur dioxide control device through an as-fired fuel analysis in lieu of data from a sulfur dioxide control system inlet gas monitor, fuel samples must be collected in accordance with the applicable paragraph in section 2. The sampling can be conducted upstream of any fuel processing, e.g., plant coal pulverization. For the purposes of this section, fuel lot size is defined as the weight of fuel consumed on one day (24 hours) and is directly related to the exhaust gas monitoring data at the outlet of the sulfur dioxide control system.

3.3.1 Fuel analysis. Fuel samples must be analyzed for suflur content and gross calorific value. The ASTM procedures for determining sulfur content are defined in the applicable paragraphs of section 2.

3.3.2 Calculation of sulfur dioxide input rate. The sulfur dioxide input rate determined from fuel analysis is calculated by:

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^7 \qquad \text{for S.I. units.}$$

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^4 \qquad \text{for English units.}$$

Where:

I_s=Sulfur dioxide input rate from as-fired fuel analysis, ng/J (lb/million Btu).
$\%S_f$=Sulfur content of as-fired fuel, on a dry basis; weight percent.
GCV=Gross calorific value for as-fired fuel, on a dry basis; kJ/kg (Btu/lb).

3.3.3 Calculation of sulfur dioxide emission reduction using as-fired fuel analysis. The sulfur dioxide emission reduction efficiency is calculated using the sulfur input rate from paragraph 3.3.2 and the sulfur dioxide emission rate, E_{SO_2}, determined in the applicable paragraph of Section 5.3. The equation for sulfur dioxide emission reduction efficiency is:

$$\%R_{g(f)} = 100 \times (1.0 - \frac{E_{SO_2}}{I_s})$$

Where:

$\%R_{g(f)}$=Sulfur dioxide removal efficiency of the sulfur dioxide control system using as-fired fuel analysis data; percent.
E_{SO_2}=Sulfur dioxide emission rate from sulfur dioxide control system; ng/J (lb/million Btu).
I_s=Sulfur dioxide input rate from as-fired fuel analysis; ng/J (lb/million Btu).

4. *Calculation of overall reduction in potential sulfur dioxide emission.*

4.1 The overall percent sulfur dioxide reduction calculation uses the sulfur dioxide concentration at the inlet to the sulfur dioxide control device as the base value. Any sulfur reduction realized through fuel cleaning is introduced into the equation as an average percent reduction, $\%R_f$.

4.2 Calculate the overall percent sulfur reduction as:

$$\%R_o = 100[1.0 - (1.0 - \frac{\%R_f}{100})\ (1.0 - \frac{\%R_g}{100})]$$

Where:

$\%R_o$=Overall sulfur dioxide reduction; percent.
$\%R_f$=Sulfur dioxide removal efficiency of fuel pretreatment from Section 2; percent. Refer to applicable subpart for definition of applicable averaging period.

$\%R_s$ = Sulfur dioxide removal efficiency of sulfur dioxide control device either O_2 or CO_2-based calculation or calculated from fuel analysis and emission data, from Section 3; percent. Refer to applicable subpart for definition of applicable averaging period.

5. *Calculation of particulate, sulfur dioxide, and nitrogen oxides emission rates.*

5.1 Sampling. Use the outlet SO_2 and O_2 or CO_2 concentrations data obtained in section 3.1. Determine the particulate, NO_x, and O_2 or CO_2 concentrations according to methods specified in an applicable subpart of the regulations.

5.2 Determination of an *F* factor. Select an average *F* factor (section 5.2.1) or calculate an applicable *F* factor (section 5.2.2). If combined fuels are fired, the selected or calculated *F* factors are prorated using the procedures in section 5.2.3. *F* factors are ratios of the gas volume released during combustion of a fuel divided by the heat content of the fuel. A dry *F* factor (F_d is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted; a wet *F* factor (F_w) is the ratio of the volume of wet flue gases generated to the calorific value of the fuel combusted; and the carbon *F* factor (F_c) is the ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted. When pollutant and oxygen concentrations have been determined in section 5.1, wet or dry *F* factors are used. (F_w factors and associated emission calculation procedures are not applicable and may not be used after wet scrubbers; F_c or F_d factors and associated emission calculation procedures are used after wet scrubbers.) When pollutant and carbon dioxide concentrations have been determined in section 5.1, F_c factors are used.

5.2.1 Average F factors. Table 1 shows average F_d, F_w, and F_c factors (scm/J, scf/million Btu) determined for commonly used fuels. For fuels not listed in table 1, the F factors are calculated according to the procedures outlined in Section 5.2.2 of this section.

5.2.2 Calculating an F factor. If the fuel burned is not listed in table 1 or if the owner or operator chooses to determine an F factor rather than use the tabulated data, F factors are calculated using the equations below. The sampling and analysis procedures followed in obtaining data for these calculations are subject to the approval of the Administrator and the Administrator should be consulted prior to data collection. For SI Units:

$$F_d = \frac{227.0(\%H) + 95.7(\%C) + 35.4(\%S) \text{ x } 8.6(\%N) - 28.5(\%O)}{GCV}$$

$$F_w = \frac{347.4(\%H)+95.7(\%C)+35.4(\%S)+8.6(\%N)-28.5(\%O)+13.0(\%H_2O)^{**}}{GCV_w}$$

$$F_c = \frac{20.0(\%C)}{GCV}$$

For English Units:

$$F_d = \frac{10^6[3.64(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)]}{GCV}$$

** The $\%H_2O$ term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.

TABLE 1. F FACTORS FOR VARIOUS FUELS

	F_d		F_w		F_c	
Fuel-Type	$\frac{\text{dscm}}{\text{J}}$	$\frac{\text{dscf}}{10^6\ \text{Btu}}$	$\frac{\text{wscm}}{\text{J}}$	$\frac{\text{wscf}}{10^6\ \text{Btu}}$	$\frac{\text{scm}}{\text{J}}$	$\frac{\text{scf}}{10^6\ \text{Btu}}$
Coal						
Anthracite[a]	2.72×10^{-7}	(10140)	2.84×10^{-7}	(10680)	0.486×10^{-7}	(1810)
Bituminous[a]	2.64×10^{-7}	(9820)	2.87×10^{-7}	(10680)	0.486×10^{-7}	(1810)
Lignite	2.66×10^{-7}	(9900)	3.22×10^{-7}	(12000)	0.515×10^{-7}	(1920)
Oil[b]	2.48×10^{-7}	(9220)	2.78×10^{-7}	(10360)	0.384×10^{-7}	(1430)
Gas						
Natural	2.35×10^{-7}	(8740)	2.86×10^{-7}	(10650)	0.279×10^{-7}	(1040)
Propane	2.35×10^{-7}	(8740)	2.75×10^{-7}	(10240)	0.322×10^{-7}	(1200)
Butane	2.35×10^{-7}	(8740)	2.80×10^{-7}	(10430)	0.338×10^{-7}	(1260)
Wood	2.49×10^{-7}	(9280)	----------	-------	0.494×10^{-7}	(1840)
Wood Bark	2.59×10^{-7}	(9640)	----------	-------	0.499×10^{-7}	(1860)

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[a] As classified according to ASTM D 388-66

[b] Crude, residual, or distillate

$$F_w = \frac{10^6[5.57(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)+0.21(\%H_2O)^*]}{GCV_w}$$

$$F_c = \frac{10^6[0.321(\%C)]}{GCV}$$

Where:

F_d, F_w, and F_c have the units of scm/J or scf/million Btu; %H, %C, %S, %N, %O, and $\%H_2O$ are the concentrations by weight (expressed in percent) of hydrogen, carbon, sulfur, nitrogen, oxygen, and water from an ultimate analysis of the fuel; and GCV is the gross calorific value of the fuel in kJ/kg or Btu/lb and consistent with the ultimate analysis. Follow ASTM D 2015* for solid fuels, D 240* for liquid fuels, and D 1826* for gaseous fuels as applicable in determining GCV.

5.2.3 Combined fuel firing F factor. For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F_d, F_w, and F_c factors determined by Sections 5.2.1 or 5.2.2 of this section shall be prorated in accordance with the applicable formula as follows:

$$F_d = \sum_{k=1}^{n} x_k F_{dk} \quad \text{or}$$

$$F_w = \sum_{k=1}^{n} x_k F_{wk} \quad \text{or}$$

$$F_c = \sum_{k=1}^{n} x_k F_{ck}$$

Where:

x_k = The fraction of total heat input derived from each type of fuel, k.

n = The number of fuels being burned in combination.

5.3 Calculation of emission rate. Select from the following paragraphs the applicable calculation procedure and calculate the particulate, SO_2, and NO_x emission rate. The values in the equations are defined as:

E = Pollutant emission rate, ng/J(lb/million Btu).

C = pollutant concentration, ng/scm(lb/scf).

NOTE.—It is necessary in some cases to convert measured concentration units to other units for these calculations. Use the following table for such conversions:

CONVERSION FACTORS FOR CONCENTRATION

From—	To—	Multiply by—
g/scm	ng/scm	10^9
mg/scm	ng/scm	10^6
lb/scf	ng/scm	1.602×10^{13}
ppm(SO_2)	ng/scm	2.660×10^6
ppm(NO_x)	ng/scm	1.912×10^6
ppm(SO_2)	lb/scf	1.660×10^{-7}
ppm(NO_x)	lb/scf	1.194×10^{-7}

5.3.1 Oxygen-based F factor procedure.

5.3.1.1 Dry basis. When both percent oxygen ($\%O_{2d}$) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_d \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

5.3.1.2 Wet basis. When both the percent oxygen ($\%O_{2w}$) and the pollutant concentration (C_w) are measured in the flue gas on a wet basis, the following equations are applicable: (NOTE.—F_w factors are not applicable after wet scrubbers.)

(a) $$E = C_w F_w \left[\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2w}}\right]$$

where:

B_{wa} = Proportion by volume of water vapor in the ambient air. Approval may be given for determination of B_{wa} by on-site instrumental measurement provided that the absolute accuracy of the measurement technique can be demonstrated to be within +0.7 percent water vapor. In lieu of actual measurement, B_{wa} may be estimated as follows:

NOTE.—The following estimating factors are selected to assure that any negative error introduced in the term

$$\left(\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2ws}}\right)$$

will not be larger than −1.5 percent. However, positive errors, or over-estimation of emissions, of as much as 5 percent may be introduced depending upon the geographic location of the facility and the associated range of ambient moisture.

(i) B_{wa} = 0.027. This factor may be used as a constant value at any location.

(ii) B_{wa} = Highest monthly average of B_{wa} which occurred within a calendar year at the nearest Weather Service Station.

(iii) B_{wa} = Highest daily average of B_{wa} which occurred within a calendar month at the nearest Weather Service Station, calculated from the data for the past 3 years. This factor shall be calculated for each month and may be used as an estimating factor for the respective calendar month.

(b) $$E = C_w F_d \left[\frac{20.9}{20.9(1 - B_{ws}) - \%O_{2w}}\right]$$

where:

B_{ws} = Proportion by volume of water vapor in the stack gas.

This equation is approved in principle. Approval for actual practice is contingent upon demonstrating the ability to accurately determine B_{ws} such that any absolute error in B_{ws} will not cause an error of more than ± 1.5 percent in the term:

$$\left(\frac{20.9}{20.9(1 - B_{ws}) - \%O_{2ws}}\right)$$

5.3.1.3. Dry/Wet basis. When the pollutant concentration (C_w) is measured on a wet basis and the oxygen concentration ($\%O_{2d}$) or measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_d}{(1 - B_{ws})}\right]\left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

NOTE.—See section 5.3.1.2 on the usage of B_{ws}. When the pollutant concentration (C_d) is measured on a dry basis and the oxygen concentration ($\%O_{2w}$) is measured on a wet basis, the following equation is applicable:

$$E = C_d F_d \left[\frac{20.9}{20.9 - \frac{\%O_{2w}}{(1 - B_{ws})}}\right]$$

---

*The $\%H_2O$ term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.

5.3.2 Carbon Dioxide-Based F Factor Procedure.

5.3.2.1 Dry Basis. When both the percent carbon dioxide ($\%CO_{2d}$) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_c \left(\frac{100}{\%CO_{2d}}\right)$$

5.3.2.2 Wet basis. When both the percent carbon dioxide ($\%CO_{2w}$) and the pollutant concentration (C_w) are measured on a wet basis, the following equation is applicable:

$$E = C_w F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.3.2.3 Dry/Wet basis. When the pollutant concentration (C_w) is measured on a wet basis and the percent carbon dioxide ($\%CO_{2d}$) is measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_c}{(1 - B_{ws})}\right] \left[\frac{100}{\%CO_{2d}}\right]$$

NOTE.—See section 5.3.1.2 on the limitation on the usage of B_{ws}.

When the pollutant concentration (C_d) is measured on a dry basis and the percent carbon dioxide ($\%CO_{2w}$) is measured on a wet basis, the following equation is applicable:

$$E = C_d (1 - B_{ws}) F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.4 Calculation of emission rate from combined cycle-gas turbine systems. For gas turbine-steam generator combined cycle systems, the emissions from supplemental fuel fired to the steam generator or the percentage reduction in potential SO_2) emissions cannot be determined directly. Using measurements from the gas turbine exhaust (performance test, subpart GG) and the combined exhaust gases from the steam generator, calculate the emission rates for these two points following the appropriate paragraphs in section 5.3 (NOTE.—F_w factors shall not be used to determine emission rates from gas turbines because of the injection of steam or to calculate emission rates after wet scrubbers; F_d or F_c factor and associated calculation procedures are used to combine effluent emissions according to the procedure in paragraph 5.2.3.) The emission rate from the steam generator is calculated as:

$$E_{sg} = \frac{E_c - X_{gt} E_{gt}}{X_{sg}}$$

where

E_{sg}=Pollutant emission rate from steam generator effluent, ng/J (lb/million Btu).
E_c=Pollutant emission rate in combined cycle effluent; ng/J (lb/million Btu).
E_{gt}=Pollutant emission rate from gas turbine effluent; ng/J (lb/million Btu).
X_{sg}=Fraction of total heat input from supplemental fuel fired to the steam generator.
X_{gt}=Fraction of total heat input from gas turbine exhaust gases.

NOTE.—The total heat input to the steam generator is the sum of the heat input from supplemental fuel fired to the steam generator and the heat input to the steam generator from the exhaust gases from the gas turbine.

5.5 Effect of wet scrubber exhaust, direct-fired reheat fuel burning. Some wet scrubber systems require that the temperature of the exhaust gas be raised above the moisture dew-point prior to the gas entering the stack. One method used to accomplish this is direct-firing of an auxiliary burner into the exhaust gas. The heat required for such burners is from 1 to 2 percent of total heat input of the steam generating plant. The effect of this fuel burning on the exhaust gas components will be less than ± 1.0 percent and will have a similar effect on emission rate calculations. Because of this small effect, a determination of effluent gas constituents from direct-fired reheat burners for correction of stack gas concentrations is not necessary.

APPENDIX E—[RESERVED]

5. Appendix E is added to part 60 and reserved.

(Sec. 111, 114, and 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, and 7601(a)).

[FR Doc. 78-26005 Filed 9-18-78; 8:45 am]

[6560-01]

[40 CFR Part 60]

[FRL 967-2]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Public hearing on Proposed Standards for Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency.

ACTION: Hearing on proposed rule.

SUMMARY: This document announces a public hearing on the standards of performance for electric utility steam generating units which are proposed in this issue of the FEDERAL REGISTER.

DATES: Hearing date: November 29-30, 1978. See Supplementary Information for additional information.

ADDRESSES: Hearing held: GSA Auditorium, 18th and F Streets NW., Washington, D.C. See Supplementary Information for additional information.

FOR FURTHER INFORMATION CONTACT:

Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: In accordance with section 307(d)(5) of the Clean Air Act, a public hearing on the standards of performance for electric utility steam generating units which are proposed in this issue of the FEDERAL REGISTER will be held as follows:

Date: November 29-30, 1978.
Place: GSA Auditorium, 18th and F Streets NW., Washington, D.C.
Time: 9 a.m. to 4 p.m.

Persons wishing to make oral presentations, which will be limited to 15 minutes each, should notify EPA by November 17, 1978, by contacting Ms. Shirley Tabler, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5421. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statements should be addressed to Jack R. Farmer, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at the U.S. Environmental Protection Agency's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street SW., Washington, D.C. 20460 (Docket No. OAQPS-78-1).

PURPOSE

As a result of a suit brought by the Sierra Club, the Agency is under a court order to promulgate final regulations within 6 months of today's proposal. This is also the maximum period of time for promulgation permitted by section 307(d)(1) of the Clean Air Act. To comply with the schedule set forth in the court's order, but at the same time to maximize the public's involvement in the rulemaking, the Agency will provide over 14 weeks for public input.

The public involvement period will be structured as follows: Written comments may be submitted by any interested member of the public for a period of 60 days. Following the public comment period, 2 days of hearings will be held. The hearings will be legislative in nature with Agency officials empaneled to receive testimony and ask questions of all witnesses. Persons interested in testifying at the hearing should advise the Agency as instructed above. Though no cross-examination will take place at the hearings, written questions directed at witnesses testifying at the hearing may be submitted to the panel by members of the audience.

It is the expectation of the Agency that the hearing testimony will concentrate on clarifying, supplementing, and rebutting previously submitted written statements. The Agency recognizes that interested persons will require a period of time prior to the hearing to read the written submissions of other interested parties so that an informed comment may be made at the public hearing. In addition, all written comments received will be placed in the docket (docket No. OAQPS-78-1) as soon after receipt as practicable. All comments received will be on file no later than 2 calendar days after the close of the 60-day comment period. The docket is available for public inspection and copying between 8 a.m. and 4 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street SW., Washington, D.C. 20460.

As required by section 307(d)(5)(iv), the record of the public hearing will remain open for 30 days after completion of the hearing to provide an opportunity for any member of the public to submit rebuttal and supplementary information on the data presented at the hearing. Upon completion of this 30-day period, the record will be closed in order to provide sufficient' time for the Administrator to carefully weigh all evidence submitted and to make the final decision on the basis of the formal record.

Dated: September 11, 1978.

DAVID G. HAWKINS,
Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 78-26006 Filed 9-18-78; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 1012-4]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Public Hearing on Proposed Standards for Electric Utility Steam Generating Units

AGENCY: Environmental Protection agency (EPA).

ACTION: Extension of comment period on proposed rule.

SUMMARY: This notice extends the comment period and changes the public hearing dates for the proposed standards of performance for electric utility steam generating units which were proposed September 19, 1978 (43 FR 42183). EPA has been requested by representatives of industry, environmental groups, and governmental agencies to allow more time to comment on the proposed standards.

DATES: Public hearing: December 12-14, 1978; 9:00 a.m. to 4:00 p.m. Comments: Comments must be received on or before December 15, 1978. Public hearing record: The public hearing record will close January 15, 1979.

ADDRESSES: Hearing held: GSA Auditorium, 18th and F Streets NW., Washington, D.C..

FOR FURTHER INFORMATION CONTACT:

Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On September 19, 1978, EPA proposed standards of performance for electric utility steam generating units under the authority of section 111 of the Clean Air Act and announced a public hearing. Comments were to be received on or before November 20, 1978, the public hearing was scheduled to be held on November 29-30, 1978, and the record of the public hearing would remain open for 30 days after completion of the hearing to provide an opportunity for any member of the public to submit rebuttal and supplementary information on the data presented at the hearing.

This notice changes those dates to the following:

Comments: Comments are to be received on or before December 15, 1978.

Public hearing: The public hearing will be held December 12-14, 1978, between the hours of 9:00 a.m. and 4:00 p.m. The public hearing record will remain open until January 15, 1979.

EPA has received requests to extend the times for filing comments on the proposed standards from the Utility Air Regulatory Group, the Sierra Club, the Department of Commerce, and others. EPA believes that the schedule changes provided in this notice should satisfy these requests.

Persons wishing to make oral presentations, which will be limited to 15 minutes each, should notify EPA by November 30, 1978, by contacting Ms. Shirley Tabler, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone 919-541-5421. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statements should be addressed to Mr. Jack R. Farmer, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711.

The public hearing will be legislative in nature with EPA officials empaneled to receive testimony and ask questions of all witnesses. Persons interested in testifying at the hearing should advise EPA as instructed above. If time permits, the third day of the hearing may be used by the hearing officer to have a panel discussion of the issues raised during the hearing. A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at the Environmental Protection Agency's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460 (Docket No. OAQPS-78-1).

In addition to revising the comment period and hearing schedule, the Agency also recognizes that the organization of the public hearing itself will have to be changed. Initially, the public hearing was to serve as a forum for clarifying, supplementing, and rebutting previously submitted written statements. This approach anticipated that most written statements would be available for review by the public in advance of the close of the comment period and that only a limited amount of time would be required between the close of the comment period and the public hearing for review of those comments received near the deadline. However, a number of individuals have indicated they will not be able to complete and submit their comments as early as contemplated by this approach.

The extension of the comment period in response to the requests of these parties will make it impossible to follow EPA's original intention of having a nine-day interval between the close of the comment period and the beginning of the hearing and still comply with the terms of the consent order issued by the U.S. District Court for the District of Columbia. The order requires the standards to be promulgated by March 20, 1979. However, all interested persons will still be provided the opportunity to reply to one another's comments and submit supplemental information, as the record will be held open for thirty days after comments are due. Upon completion of this 30-day period (January 15, 1979), the record will be closed in order to provide sufficient time for the Administrator to carefully weigh all evidence submitted and to make the final decision on the basis of the formal record.

Dated: November 16, 1978.

David D. Hawkins,
Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 78-32821 Filed 11-22-78; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 1012-3]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Electric Utility Steam Generating Units; Correction and Additional Information

AGENCY: Environmental Protection Agency.

ACTION: Corrections and Additional Information on proposed rule.

SUMMARY: This notice corrects information that appeared in the Federal Register on September 19, 1978 (43 FR 42164 and 42168), and provides information on the additional analyses being conducted.

On September 19, 1978 (43 FR 42154), EPA proposed standards of performance which would limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified and reconstructed electric utility steam generating units capable of combusting more than 73 megawatts (MW) heat input (250 million Btu/hour) of fossil fuel. In that proposal, EPA indicated that a final decision on full versus partial SO_2 scrubbing would not be made until the analyses of various alternatives were completed and public comments evaluated. The purpose of this notice is to correct certain errors in Tables 7 and 8 contained in the preamble; to clearly identify certain documents in the docket (Docket Number OAQPS-78-1); and to advise the public of the additional analyses that are being undertaken.

DATES: Comments on this information may be submitted to EPA through January 15, 1979.

ADDRESSES: Comments should be submitted to Jack R. Farmer, Chief, Standards Development Branch, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT:

Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION: The corrections and additinal information follow.

1. As a result of EPA's continuing analysis of the costs of the alternative standards, certain errors pertaining to average monthly residential bills and the incremental utility capital expenditures were identified in Tables 7 and 8 of the preamble of the September 19 proposal. The corrected tables are presented in this notice.

2. The "real resource" present value (presented in the second full paragraph of column one [43 FR 42164]) should also be corrected to read $17.5 billion for the full control option and $10.1 billion for the 340 ng/J (0.80 lb/million Btu) option as compared to the current standard.

3. In addition, it is also necessary to correct average monthly residential bills and the incremental utility capital expenditures in Tables 3-5 and 3-6 found on pages 3-15 and 3-19, respectively, of the document, "Background Information for Proposed SO_2 Emission Standards-Supplement," EPA-450/2-78-007a-1. The corrected tables are presented in this notice.

Table 7. SUMMARY OF 1990 ECONOMIC IMPACTS[a]

	Level of Control									
	Current Standards		Full Control		Partial Control					
					210 ng/J		290 ng/J		340 ng/J	
	APR	AUG	APR	AUG	APR	AUG	APR	AUG	APR	AUG
Average monthly residential bills ($/month)	45.31	43.83	46.39	44.17	46.20	44.43	--	44.21	45.47	44.19
Incremental Utility Capital Expenditures, Cumulative 1976-1990[a] ($ billions)	--	--	10	-2	15	6	--	2	3	2
Incremental Annualized Cost ($ billions)	--	--	2.0	1.9	1.3	1.7	--	1.3	0.3	1.1
Incremental Cost of SO_2 Reduction ($/ton)	--	--	885	754	640	642	--	511	303	485

SOURCE: Background Information for Proposed SO_2 Emission Standards - Supplement, EPA-450/2-78-007a-1, Chapters 2 and 3, August, 1978.

[a] Results of EPA analyses completed in April, 1978, and August, 1978.

Table 8. SUMMARY OF 1995 IMPACTS: AUGUST, 1978, ANALYSIS

	Level of Control					
	1975 Actual	Current Standards	Full Control	Partial Control		
				210 ng/J	290 ng/J	340 ng/J
National Emissions (million tons)	18.6	23.3	18.5	18.5	18.7	19.0
New Plant Emissions[a] (million tons)	--	7.9	2.4	2.5	2.8	3.2
U.S. Coal Production (million tons)	647	1865	1865	1858	1868	1866
Western Coal Shipped East (million tons)	21	210	130	133	190	196
Oil/Gas Consumption (million bbl/day)	3.1	0.8	0.9	0.9	0.9	0.9
Incremental Cumulative Capital Expenditures (1975 $ billion)	--	--	27	22	15	13
Incremental Annualized Cost (1975 $ billion)	--	--	2.6	2.3	2.0	1.9
Average Monthly Residential Bill (1975 $/month)	--	45.34	46.31	46.10	46.02	45.98
Total Coal Capacity (GW)	198	587	580	580	580	580

SOURCE: Background Information for Proposed SO_2 Emission Standards - Supplement, EPA-450/2-78-007a-1, Chapter 3, August, 1978.

[a] Plants subject to the revised standards.

Table 3-5. RESIDENTIAL BILLS, CAPITAL EXPENDITURES, PRESENT VALUES, AND ANNUALIZED COSTS

Control Options

	Current NSPS	0.2		0.5		0.67	0.8
		With Exemptions	Without Exemptions	With Exemptions	Without Exemptions	With Exemptions	With Exemptions
I. 1990 monthly national avg residential bills, $/mo	43.83	44.17	44.30	44.43	44.55	44.21	44.19
Utility capital expenditures, $ billions	476.90	475.00	474.30	482.60	481.30	478.50	478.50
Present value - increase over current NSPS - $ billions	--	17.50	22.10	15.30	19.40	11.10	10.10
Annualized cost - $ billions	91.50	93.40	93.80	93.20	93.60	92.80	92.60
II. 1995 monthly national avg residential bills, $/mo	45.34	46.31	46.63	46.10	46.38	46.02	45.98
Utility capital expenditures, $ billions	730.20	756.80	757.30	752.20	750.30	745.40	743.10
Present value - increase over current NSPS - $ billions	--	18.00	27.20	17.10	24.40	14.30	13.70
Annualized cost, $ billions	125.60	128.20	129.20	127.90	128.70	127.60	127.50

Table 3-6. A COMPARISON OF ALTERNATIVE OIL PRICE AND RAIL RATE ASSUMPTIONS UPON RESULTS FOR THE 0.2 (WITH EXEMPTIONS) OPTION IN 1990 (CONTINUED)

	BASE CASE[1]	LOW OIL PRICE[2]	VERY LOW OIL PRICE[3]	NO RAIL RATE ESCALATION[4]
V. Selected Economic Information[8]				
. Monthly National Avg. Residential Bill, $/mo	44.17	43.62	42.57	NA
. Utility Capital Expenditures, $ Billions Cumulative	475.00	450.10	405.70	NA
. Present value - Increase Over Current NSPS, $ Billions	17.50	11.80	12.31	NA
. Annualized Cost, $ Billions	93.40	91.30	87.10	NA

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[1] 1990 oil price of $20.00/bbl; rail rate escalation of 1% over inflation.

[2] 1990 oil price of $17.00/bbl; rail rate escalation of 1% over inflation.

[3] 1990 oil price of $12.70/bbl; rail rate escalation of 1% over inflation.

[4] 1990 oil price of $20.00/bbl; rail rate escalation of 1% over inflation.

[5] Existing plants subject to SIPs.

[6] New plants required to meet the current NSPS of 1.2 lb SO_2/million Btu.

[7] Plants required to meet the revised (alternative) NSPS.

[8] All economic data are presented in 1975 dollars. All cost information includes costs for controlling particulate emissions for new sources to a level of 0.03 lbs per million Btu.

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4. It has come to EPA's attention that some interested parties are having difficulty in identifying the documents that constitute the economic impact assessment that was prepared in accordance with Section 317 of the Clean Air Act. These documents are:

"Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards." EPA 450/2-78-006a

"Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standards," EPA 450/2-78-002a

"Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards," EPA 450/2-78-007a

"Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards-Supplement," EPA 450/2-78-007a-01. In addition, EPA has prepared the following list of documents which provided background information for the preparation of the economic impact assessment. All of these documents are contained in Docket Number OAQPS-78-1, which is located at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

Category and Title

II-A-18 EPA-45/3-78-045, February, 1977, Electrostatic Precipitator Costs for Large Coal-Fired Steam Generators.

II-A-24 EPA-450/3-78-046, August, 1977, Fabric Filter Costs for Large Coal-Fired Steam Generators.

II-A-47 EPA-45-/3-78/043, November, 1977, Flue Gas Desulfurization System Manufacturers Survey.

II-A-64 EPA-450/3-78-007, February, 1977, Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers.

II-A-66 EPA-450/3-78-004, February, 1978, Assessment of Manufacturers Capability to Meet Requirements for Particulate Controls on Utility and Industrial Boilers.

II-A-68 Review of New Source Performance Standards for Coal-Fired Utility Boilers, Volume II, Economic and Financial Impacts, March, 1978, Teknekron, Inc.

II-A-85 The Demand for Western Coal and Its Sensitivity to Key Uncertainties, Draft Report, Second Edition, June, 1978, ICF, Inc. (Prepared for DOE.)

II-A-87 Draft Report (Update of Item Number II-A-64) Flue Gas Desulfurization Costs for Large Coal-Fired Steam Generators, PEDCo Environmental.

II-A-90 Effects of Alternative New Source Performance Standards for Coal-Fired Electric Utility Boilers on the Coal Markets and Utility Capacity Expansion Plans, Draft Reports, September, 1978, ICF, Inc. (Prepared for EPA.)

II-A-91 Further Analysis of Alternative New Source Performance Standards for Coal-Fired Power Plants, Preliminary Draft, September, 1978, ICF, Inc. (Submitted to EPA and DOE.)

II-A-321 Letter from Michael Allen, Temple, Barker and Sloane, Inc., to Lou Pugliaresi, Office of Planning and Evaluation, EPA, dated April 18, 1978. Subject: NSPS Analysis Results.

II-D-420 Letter, Dave Watkins, ICF, Inc., to Dan Badger, *et. al.*, Department of Energy, dated August 7, 1978. Subject: Summary sheets for scenarios involving low oil prices and no rail escalation.

II-D-435 Letter, Michael Allen, Temple, Barker and Sloane, Inc., to Dave Shaver, Office of Planning and Evaluation, EPA, dated August 23, 1978. Subject: NSPS Analysis Results.

II-F-4 Letter, J. F. O'Leary, Department of Energy, to D. C. Costle, EPA, dated July 6, 1978. Subject: DOE Analysis of Alternative Proposals.

IV-B-4 Memo from Michael Allen, Temple, Barker and Sloane, Inc., to Dave Shaver, Office of Planning and Evaluation, EPA, dated September 29, 1978. Subject: Changes in the TBS NSPS Analysis.

5. EPA is continuing to analyze alternative standards of performance for limiting the emission of SO_2 from power plants. As part of this effort, EPA staff has met with representatives of the Department of Energy (DOE), the Council of Economic Advisors, the Council on Wage and Price Stability, and others for the purpose of reexamining the assumptions used for the April and August analyses. As a result of these meetings, certain assumptions have been revised for the analysis currently being conducted. These changes include different oil prices from those used in the April and August analyses. For the current round of analyses, EPA will examine the various alternative standards using two ranges of oil prices. These are presented below in 1975 dollars:

1985—\$12.30, 1985—\$12.90; 1990—\$13.20, 1990—\$16.40; 1995—\$14.90, 1995—\$21.00.

In determining which oil prices to use, EPA sought guidance from DOE and others. Pending their final recommendations, EPA selected oil prices which appeared to be most consistent with those being used in the most recent analysis of the national energy plan.

In addition to oil prices, adjustments are also being made to the assumed nuclear capacity. Scrubber costs have also been refined. These changes will be presented in detail when the new analyses are released prior to the public hearing on the proposed standards. The other assumptions used in the August analysis (see Table 1, 43 FR 42165) will be retained.

With respect to the analysis of alternative standards, EPA is reanalyzing the proposed full control option as well as the DOE and Utility Air Regulatory Group recommendations. EPA is also examining other forms of both the full and partial control options. Under full control, different reduction requirements, maximum allowable emission limitations, and maximum control levels are being considered. Under partial control, other options would vary the percent reduction requirement and maximum allowable emission limitation as a function of coal sulfur content.

EPA intends to make results of these analyses available so they can be considered at the public hearing scheduled for December 12, 13, 14 Washington, D.C. Interested persons will also be afforded an opportunity to submit written comments on the results of these analyses and their underlying assumptions through January 15, 1978.

Dated: November 8, 1978.

David D. Hawkins,
Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 78-32820 Filed 11-24-78; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 1022-6]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Electric Utility Steam Generating Units; Additional Information

AGENCY: Environmental Protection Agency.

ACTION: Additional Information on Proposed Rule.

SUMMARY: On September 19, 1978 (43 FR 42154), EPA proposed standards of performance which would limit emissions of sulfur dioxide (SO$_2$), particulate matter, and nitrogen oxides (NO$_x$) from new, modified, and reconstructed electric utility steam generating units capable of combusting more than 73 megawatts (MW) heat input (250 million Btu/hour) of fossil fuel. In that proposal, EPA indicated that a final decision on full versus partial SO$_2$ scrubbing would not be made until the analyses of various alternatives were completed and public comments evaluated. The purpose of this notice is to advise the public of the preliminary results of additional analyses that have been undertaken since September 19, 1978. It should be noted that these results have not been fully reviewed by the EPA technical staff, nor have the alternative standards undergone policy review by the Agency.

DATES: Comments on this information may be submitted to EPA through January 15, 1979.

ADDRESSES: Comments should be submitted to Mr. Jack R. Farmer, Chief, Standards Development Branch, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT:

Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTAL INFORMATION: Since revisions to the standards of performance for power plants were proposed on September 19, 1978, EPA has conducted additional analyses in order to identify the economic, environmental, and energy impacts associated with various alternative sulfur dioxide standards. As part of this effort, the EPA staff met with representatives of the Department of Energy, Council of Economic Advisors, Council on Wage and Price Stability, and others for the purpose of reexamining the assumptions used for the August analysis and to develop alternative forms of the standard for analysis. As a result, certain assumptions were changed and a number of new regulatory alternatives were defined. EPA again employed the economic model that was used in August to project the national and regional impacts associated with each alternative considered.

IMPACTS ANALYZED

The environmental impacts of the alternative standards were examined by projecting pollutant emissions. Sulfur dioxide emissions were estimated nationally and by geographic region for each plant type, fuel type, and age category. EPA has also estimated the quantity of flue gas desulfurization (FGD) sludge generated by the various alternatives considered.

The economic and financial effects of the alternatives were examined in terms of capital and annualized costs. This assessment included an estimation of the utility capital expenditures for new plant and pollution control equipment as well as the fuel costs and operating and maintenance expenses associated with the plant and equipment. The impact on consumers was determined by analyzing the effect of the alternatives on average monthly residential bills. The alternatives were also examined in terms of cost per ton of SO$_2$ removed. Finally, an estimate was made of the present value of utility revenue requirements for the various alternatives.

The effects of the alternative standards on energy production and consumption were also analyzed. National coal use was projected in terms of production and consumption by geographic region. The amount of Western coal shipped to the Midwest and East was also estimated. In addition, utility consumption of oil and gas was analyzed.

MAJOR ASSUMPTIONS

A number of changes have been made in the assumptions which will have an effect on the results of the analyses. The assumptions changed from the August analysis are summarized in Table 1 and are discussed below.

After conferring with appropriate Federal agencies, it was concluded that the oil prices assumed in the August analysis were too high. On the other hand, no firm guidance was available as to what oil prices should be used. In view of this, EPA decided that the best course of action was to use two sets of oil prices which reflect the best estimates of those governmental entities concerned with projecting future oil prices. It was EPA's intention to model each regulatory alternative considered with both sets of oil prices. Unfortunately, the results from the analysis incorporating the lower of the two new oil prices were not completed in time to be included in this notice. A summary will be presented at the Public Hearing on December 12, 1978.

Reassessment of the assumptions made in the August analysis also revealed that the impact of the coal washing credit had not been considered in the modeling analysis. Other credits allowed by the September proposal, such as sulfur removed by the pulverizers or in bottom ash and flyash, were determined not to be significant when viewed at the national and regional levels. The coal washing credit, on the other hand, was found to have a significant effect on predicted emissions levels and, therefore, was taken into consideration in the results presented here.

As a result of this reassessment, refinements also have been made in the flue gas desulfurization (FGD) costs assumed. These refinements include changes in sludge disposal costs, energy penalties calculated for reheat, and module sizing. In addition, an error was corrected in the calculation of partial scrubbing costs. These changes have resulted in relatively higher partial scrubbing costs when compared to full scrubbing.

Changes have been made in the FGD availability assumption also. Previous analyses assumed 100 percent availability of FGD systems. This assumption was in conflict with EPA's estimates on module availability. In view of this, three selected alternatives in the current analyses were analyzed at a lower system availability consistent with a 90 percent availability for individual modules when the system is equipped with one spare. EPA believes that the new approach better reflects the performance of well designed, operated, and maintained FGD systems. However, in order to expedite the analyses, all the alternatives were initially analyzed with an assumed system availability of 100 percent.

Additional refinements included a change in the capital charge rate for pollution control equipment to conform to the Federal tax laws on depreciation, and the addition of 100 million tons of coal reserves not previously accounted for in the model.

Finally, a number of less significant adjustments were made. These included adjustments in nuclear capacity to reflect a cancellation of a plant, consideration of oil consumption in transporting coal, and the adjustment of costs to 1978 dollars rather than 1975 dollars. It should be understood that all costs include the costs of complying with the proposed particulate standard and nitrogen oxide standards, as well as the sulfur dioxide alternatives.

DESCRIPTION OF ALTERNATIVES ANALYZED

This section presents a description of the alternatives analyzed since the September 19 proposal. The short title on each alternative corresponds to the column headings used in the tables which follow. In structuring alternatives, a range of options was developed as a means of assessing the impacts of emission control requirements which are both more and less stringent than those identified in the September proposal. These alternatives, which are described below, include three full scrubbing options requiring 90 percent control, one full scrubbing option requiring 95 percent control, seven partial scrubbing options, and three sensitivity runs. In addition, EPA undertook analyses of alternatives specified by the Utility Air Regulatory Group (UARG) and the Natural Resources Defense Council (NRDC). A preliminary review of the results revealed that certain errors were made in the modeling specifications for the UARG and NRDC alternatives. As a result, the cases actually modeled did not conform to specifications provided by UARG and NRDC. Therefore, EPA is reanalyzing these alternatives and will release the results as soon as they are available.

In view of the wide variety of alternatives considered since the proposal, all standards are presented as annual average emission limitations in order to provide a common basis for comparison. In the analysis presented in September, all standards were described in terms of 24-hour averages, but were converted to annual averages for modeling purposes. This conversion was necessary because the model requires emission standards to be expressed in terms of annual averages, which can be substantially different from standards based on other averaging times. For example, because of the variability in outlet sulfur emissions, EPA has determined that an annual emission rate of 0.8 lb SO_2/million Btu heat input would be required to comply with a 24-hour emission rate of 1.2 lb SO_2/million Btu heat input (with three exemptions per month). The use of annual average descriptors should not be construed to mean that EPA has made a final decision regarding averaging periods.

A. FULL CONTROL ALTERNATIVES

1. *90 Percent Control With 340 ng/J Limit*—This alternative corresponds to the full control alternative proposed in September. For modeling purposes, this alternative is specified as 90 percent reduction in potential SO_2 emissions with a 340 ng/J (0.8 lb SO_2/million Btu) heat input maximum allowable emission limitation. Credit toward the 90 percent reduction requirement is allowed for any sulfur removed through coal washing. However, the maximum allowable emission limitation precludes the application of the full coal washing credit when certain high-sulfur coals are fired.

2. *90 Percent Control With 240 ng/J Limit*—This alternative corresponds to the one described above except that a lower maximum allowable emission limit of 240 ng/J (0.55 lb SO_2/million Btu) heat imput is specified. In the model, the maximum allowable emission limitation precludes coals greater than 2150 ng/J (5.0 lb SO_2/million Btu) heat input after washing.

3. *90 Percent Reduction Across Scrubber*—This alternative requires a 90 percent efficient scrubber. A maximum allowable emission limitation of 340 ng/J (0.8 lb SO_2/million Btu) heat input is also specified.

B. PARTIAL CONTROL ALTERNATIVES

4. *240 ng/J Emission Limit*—This alternative has a maximum allowable emission limitation of 240 ng/J (0.55 lb SO_2/million Btu) heat input with a minimum requirement of 33 percent reduction in potential SO_2 emissions. This results in varying control requirements ranging from 33 percent on low-sulfur coals to 90 percent for high-sulfur coals. In the model, the maximum allowable emission limitation precludes coals greater than 2150 ng/J (5.0 lb SO_2/million Btu) heat input.

5. *90 Percent Control With 330 ng/J Maximum Control*—This alternative requires 90 percent control of potential SO_2 emissions with a maximum allowable emission limit of 340 ng/J (0.8 lb SO_2/million Btu) heat input. The maximum control level is 330 ng/J (0.77 lb SO_2/million Btu) heat input, but a minimum of 22 percent reduction in potential SO_2 emissions is required. The 330 ng/J (0.77 lb SO_2/million Btu) heat input maximum control level will allow partial scrubbing on coals below about 1510 ng/J (3.5 lb SO_2/million Btu) heat input.

6. *Sliding Scale With 90 Percent Control in West*—This option requires 90 percent control of potential SO_2 emissions in the eleven western-most States. Partial scrubbing is allowed in the remaining States. The partial scrubbing standard is a sliding scale emission control requirement based on the sulfur content of coal burned. The scale slides from 50 percent control of potential SO_2 emissions for low-sulfur coal up to 90 percent control on high-sulfur coals. In the model, the maximum allowable emissions limitation precludes coals greater than 2150 ng/J (5.0 lb SO_2/million Btu) heat input.

7. *240 ng/J Standard With 90 Percent Control in West*—This option corresponds to the one above except that the partial scrubbing standard for Eastern States has been modified. The modified partial scrubbing standard is a uniform emission limit of 240 ng/J (0.55 lb SO_2/million Btu) heat input with a minimum control requirement of 33 percent reduction in potential SO_2 emissions (same standard as option 4 above). In the model, the maximum allowable emission limitation precludes coals greater than 2150 ng/J (5.0 lb SO_2/million Btu) heat input.

8. *90 Percent Control With 150 ng/J Maximum Control*—This alternative requires 90 percent control of potential SO_2 emissions with a maximum allowable emission limit of 260 ng/J (0.6 lb SO_2/million Btu) heat input. The maximum control level is 150 ng/J (0.35 lb SO_2/million Btu) heat input with a minimum requirement of 22 percent reduction in potential SO_2 emissions. The 150 ng/J (0.35 lb SO_2/million Btu) heat input maximum control level will allow partial scrubbing on coals below about 780 ng/J (1.8 lb SO_2/million Btu) heat input.

9. *90 Percent Control With 240 ng/J Maximum Control*—This alternative requires 90 percent control of potential SO_2 emissions with a maximum allowable emission limit of 24 ng/J (0.8 lb SO_2/million Btu heat input. The maximum control level is 240 ng/J (0.55 lb SO_2/million Btu) heat input with a minimum control requirement of 33 percent reduction in potential SO_2 emissions. The 240 ng/J (0.55 lb SO_2/million Btu) heat input maximum control level will allow partial scrubbing on coals below about 800 ng/J (2.8 lb SO_2/million Btu) heat input.

10. *Sliding Scale With 520 ng/J Limit*—This alternative is a sliding scale percent removal requirement based on the sulfur content of coal burned. The percent removal requirement varies from 20 percent on low-sulfur coal to 82 percent on high-sulfur coal. The maximum allowable emission limit is 520 ng/J (1.2 lb SO_2/million Btu) heat input.

C. 95 PERCENT CONTROL WITH 340 NG/J LIMIT

This alternative requires 95 percent control of potential SO_2 emissions. A maximum allowable emission limitation of 340 ng/J (0.8 SO_2/million Btu) heat input is specified.

In addition to different emission control requirements, this case contains a cost assumption that varies from all the other cases being analyzed. It assumes that flue gas desulfurization (FGD) systems can achieve a 95 percent control efficiency annually with the use of scrubber slurry additives such as adipic acid. It was assumed that the cost of such additives will be offset by a reduction in lime/limestone use. Since the cost of the additive handling equipment is small relative to total FGD costs, the same set of FGD cost functions was used as those for costing the 90 percent efficient scrubbers assumed for the other alternatives. Finally, it was assumed that the costs of building and operating scrubbers would decline over time as a result of design improvements and competitive forces in the marketplace. Costs were assumed to decline to two-thirds of the current cost in 1985 and one-half of current cost in 1990.

D. AVAILABILITY ANALYSES

As indicated earlier, several alternatives were analyzed with scrubber system availabilities consistent with 90 percent availability for individual FGD modules. In a manner consistent with the emergency by-pass provision of the September proposal, the analyses assumed a mix of load-shifting and by-pass around the scrubber during periods when the scrubber was not available for use. These analyses were performed for the following two full scrubbing alternatives and one partial control alternative, each of which has been described above:

90 Percent Control With 240 ng/J Limit
90 Percent Control Across Scrubber
240 ng/J Emission Limit

SUMMARY OF RESULTS

The results of these analyses are presented in Tables 2-8. It should be noted that these are preliminary results that have not been fully reviewed by technical staff and therefore may have to be changed to correct computational errors. In addition, the alternatives presented have not undergone policy review by the Agency. Therefore, it should not be construed that the EPA has made any decision regarding the final form of the SO_2 standard. The results of these analyses are being released at this time in order to provide the public with information on a wide range of alternatives at the earliest possible time.

The summary results of the analyses, which were used to prepare this notice, have been compiled and are available in the public record (Docket No. OAQPS-78-1). A detailed report, including a description of the alternatives and modeling results as well as regional data, will be prepared and placed in the record by January when all of the alternatives and sensitivity analyses have been completed.

Persons may comment on these results at the Public Hearing scheduled for December 12, 13, and 14 in Washington, D.C. Interested persons also will be afforded an opportunity to submit written comments on the results of these analyses and their underlying assumptions through January 15, 1978.

Dated: December 6, 1978.

EDWARD F. TUERK,
Acting Assistant Administrator for Air, Noise, and Radiation.

294

Table 1, COMPARISON OF ASSUMPTIONS
August 1978 and November 1978

Assumption	August	November	
Growth rates	1975-1985: 4.8%/yr 1985-1995: 4.0%	same same	
Nuclear capacity	1985: 97 GW 1990: 165 1995: 230	same 1990: 165 GW 1995: 228	
Oil prices ($ 1975)		Run 1	Run 2
	1985: $15/bbl 1990: $20 1995: $28	1985: $12.90/bbl 1990: $16.40 1995: $21.00	$12.30/bbl $13.20 $14.90
General inflation rate	5.5%/yr	same	
Coal transportation	Increases at general inflation rate plus 1%	same	
Coal mining labor costs	U.M.W. settlement and 1% real increase thereafter	same	
Capital charge rate	10%	12.5%	
Cost reporting basis	1975 dollars	1978 dollars	
Coal cleaning credit	No	Yes	
FGD Costs	--	Refined	

Table 2A. NATIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS WITH 100 PERCENT FGD RELIABILITY[a]
(million tons)

Plant Category	Level of Control				
			Full Control		
	1975 Actual	Current Standards	90% Control With 340 ng/J Limit	90% Control With 240 ng/J Limit	90% Control Across Scrubber
SIP/NSPS Plants[b]	--	16.1	16.4	16.5	16.5
New Plants[c]	--	3.6	1.6	1.2	1.1
Oil Plants	--	1.8	1.9	1.9	1.9
Total National Emissions	18.6	21.5	19.9	19.6	19.5
Total Coal Capacity (GW)	198	406	391	390	390

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Plants subject to existing State regulations or the current NSPS of 1.2 lb SO_2/million Btu.

[c] Plants subject to the revised standards.

Table 2B. NATIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS WITH 100 PERCENT FGD RELIABILITY[a]
(million tons)

	Level of Control					
			Partial Control			
Plant Category	1975 Actual	Current Standards	240 ng/J Emission Limit	90% Control With 330 ng/J Max. Control	Sliding Scale With 90% Control in West	240 ng/J Std. With 90% Control in West
SIP/NSPS Plants[b]	--	16.1	16.5	16.4	16.5	16.4
New Plants[c]	--	3.6	1.6	2.2	1.3	1.4
Oil Plants	--	1.8	1.9	1.8	1.9	1.9
Total National Emissions	18.6	21.5	20.0	20.4	19.7	19.7
Total Coal Capacity (GW)	198	406	399	401	394	398

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Plants subject to existing State regulations or the current NSPS of 1.2 lb SO_2/million Btu.

[c] Plants subject to the revised standards.

Table 2C. NATIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS WITH 100 PERCENT FGD RELIABILITY[a]
(million tons)

Plant Category	Level of Control					
			Partial Control			
	1975 Actual	Current Standards	90% Control With 150 ng/J Max. Control	90% Control With 240 ng/J Max. Control	Sliding Scale With 390 ng/J Limit	95% Control With 520 ng/J Limit
SIP/NSPS Plants[b]	--	16.1	16.6	16.5	16.2	16.4
New Plants[c]	--	3.6	1.3	1.9	3.1	0.8
Oil Plants	--	1.8	1.9	1.9	1.8	1.8
Total National Emissions	18.6	21.5	19.8	20.3	21.1	19.0
Total Coal Capacity (GW)	198	406	396	399	401	400

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Plants subject to existing State regulations or the current NSPS of 1.2 lb SO_2/million Btu.

[c] Plants subject to the revised standards.

Table 2D. NATIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS WITH 90 PERCENT FGD RELIABILITY[a]
(million tons)

			Level of Control		
			------------ Full Control	---------	Partial Control
Plant Category	1975 Actual	Current Standards	90% Control With 240 ng/J Limit	90% Control Across Scrubber	240 ng/J Emission Limit
SIP/NSPS Plants[b]	--	16.1	16.5	16.5	16.6
New Plants[c]	--	3.6	1.2	1.1	1.6
Oil Plants	--	1.8	2.0	2.0	1.9
Total National Emissions	18.6	21.5	19.7	19.6	20.1
Total Coal Capacity (GW)	198	406	388	388	397

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Plants subject to existing State regulations or the current NSPS of 1.2 lb SO_2/million Btu.

[c] Plants subject to the revised standards.

Table 3A. REGIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS WITH 100 PERCENT FGD RELIABILITY[a]
(million tons)

	Level of Control				
			Full Control		
	1975 Actual	Current Standards	90% Control With 340 ng/J Limit	90% Control With 240 ng/J Limit	90% Control Across Scrubber
Total National Emissions	18.6	21.5	19.9	19.6	19.5
Regional Emissions					
East[b]	--	7.0	6.6	6.4	6.4
East South Central[c]	--	3.2	3.0	2.9	2.9
Midwest[d]	--	5.4	5.5	5.5	5.5
Great Plains[e]	--	2.4	2.3	2.3	2.3
West South Central[f]	--	2.2	1.6	1.6	1.6
West[g]	--	1.3	0.9	0.9	0.9
Total Coal Capacity (GW)	198	406	391	390	390

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] New England, Middle Atlantic, and South Atlantic Census Regions.

[c] East South Central Census Region.

[d] East North Central Census Region.

[e] West North Central Census Region.

[f] West South Central Census Region.

[g] Mountain and Pacific Census Regions.

Table 3B. REGIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS WITH 100 PERCENT FGD RELIABILITY[a]
(million tons)

	Level of Control					
			Partial Control			
	1975 Actual	Current Standards	240 ng/J Emission Limit	90% Control With 330 ng/J Max. Control	Sliding Scale With 90% Control in West	240 ng/J Std. With 90% Control in West
Total National Emissions	18.6	21.5	20.0	20.4	19.7	19.7
Regional Emissions						
East[b]	--	7.0	6.4	6.6	6.4	6.4
East South Central[c]	--	3.2	2.9	3.0	2.9	2.9
Midwest[d]	--	5.4	5.5	5.5	5.4	5.4
Great Plains[e]	--	2.4	2.4	2.4	2.5	2.4
West South Central[f]	--	2.2	1.8	1.9	1.7	1.8
West[g]	--	1.3	1.0	1.1	0.9	0.9
Total Coal Capacity (GW)	198	406	399	401	394	398

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] New England, Middle Atlantic, and South Atlantic Census Regions.

[c] East South Central Census Region.

[d] East North Central Census Region.

[e] West North Central Census Region.

[f] West South Central Census Region.

[g] Mountain and Pacific Census Regions.

Table 3C. REGIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS WITH 100 PERCENT FGD RELIABILITY[a]
(million tons)

Level of Control

	1975 Actual	Current Standards	90% Control With 150 ng/J Max. Control	90% Control With 240 ng/J Max. Control	Sliding Scale With 390 ng/J Limit	95% Control With 520 ng/J Limit
			Partial Control			
Total National Emissions	18.6	21.5	19.8	20.3	21.1	19.0
Regional Emissions						
East[b]	--	7.0	6.4	6.5	6.9	6.2
East South Central[c]	--	3.2	2.9	3.0	3.2	2.8
Midwest[d]	--	5.4	5.6	5.6	5.5	5.5
Great Plains[e]	--	2.4	2.3	2.4	2.4	2.2
West South Central[f]	--	2.2	1.6	1.7	2.0	1.5
West[g]	--	1.3	1.0	1.0	1.2	0.8
Total Coal Capacity (GW)	198	406	396	399	401	400

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] New England, Middle Atlantic, and South Atlantic Census Regions.

[c] East South Central Census Region.

[d] East North Central Census Region.

[e] West North Central Census Region.

[f] West South Central Census Region.

[g] Mountain and Pacific Census Regions.

Table 30. REGIONAL 1990 SO_2 EMISSIONS FROM UTILITY BOILERS WITH 90 PERCENT FGD RELIABILITY[a]
(million tons)

	Level of Control				
			Full Control		Partial Control
	1975 Actual	Current Standards	90% Control With 240 ng/J Limit	90% Control Across Scrubber	240 ng/J Emission Limit
Total National Emissions	18.6	21.5	19.7	19.6	20.1
Regional Emissions					
East[b]	--	7.0	6.4	6.4	6.5
East South Central[c]	--	3.2	2.9	2.9	2.9
Midwest[d]	--	5.4	5.6	5.5	5.5
Great Plains[e]	--	2.4	2.3	2.3	2.4
West South Central[f]	--	2.2	1.6	1.6	1.8
West[g]	--	1.3	0.9	0.9	1.1
Total Coal Capacity (GW)	198	406	388	388	397

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $15.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] New England, Middle Atlantic, and South Atlantic Census Regions.

[c] East South Central Census Region.

[d] East North Central Census Region.

[e] West North Central Census Region.

[f] West South Central Census Region.

[g] Mountain and Pacific Census Regions.

Table 4A. IMPACTS ON FUELS IN 1990 WITH 100 PERCENT FGD RELIABILITY[a]

	Level of Control				
			Full Control		
	1975 Actual	Current Standards	90% Control With 340 ng/J Limit	90% Control With 240 ng/J Limit	90% Control Across Scrubb
U.S. Coal Production (million tons)					
Appalachia	--	419	399	398	398
Midwest	--	348	390	390	390
Northern Great Plains	--	463	458	460	461
West	--	211	188	188	188
TOTAL	647	1441	1435	1436	1437
Western Coal Shipped East (million tons)	21	84	62	64	64
Oil Consumption by Power Plants (million bbl/day)					
Power Plants	--	1.8	2.0	2.1	2.1
Coal Transportation	--	0.1	0.2	0.1	0.1
TOTAL	3.1	1.9	2.2	2.2	2.2

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[a] Results of EPA analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

Table 4B. IMPACTS ON FUELS IN 1990 WITH 100 PERCENT FGD RELIABILITY[a]

		Level of Control				
			Partial Control			
	1975 Actual	Current Standards	240 ng/J Emission Limit	90% Control With 330 ng/J Max. Control	Sliding Scale With 90% Control in West	240 ng/J Std. With 90% Control in West
U.S. Coal Production (million tons)						
Appalachia	--	419	412	415	411	411
Midwest	--	348	377	373	367	377
Northern Great Plains	--	463	455	451	465	459
West	--	211	200	202	196	197
TOTAL	647	1441	1444	1441	1439	1444
Western Coal Shipped East (million tons)	21	84	62	67	85	64
Oil Consumption by Power Plants (million bbl/day)						
Power Plants	--	1.8	1.9	1.9	2.0	1.9
Coal Transportation	--	0.1	0.1	0.1	0.1	0.1
TOTAL	3.1	1.9	2.0	2.0	2.1	2.0

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[a] Results of EPA analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

Table 4C. IMPACTS ON FUELS IN 1990 WITH 100 PERCENT FGD RELIABILITY[a]

	Level of Control					
			Partial Control			
	1975 Actual	Current Standards	90% Control With 150 ng/J Max. Control	90% Control With 240 ng/J Max. Control	Sliding Scale With 390 ng/J Limit	95% Control With 520 ng/ Limit
U.S. Coal Production (million tons)						
Appalachia	--	419	403	406	410	403
Midwest	--	348	392	385	372	394
Northern Great Plains	--	463	445	451	465	465
West	--	211	199	199	198	188
TOTAL	647	1441	1439	1441	1445	1450
Western Coal Shipped East (million tons)	21	84	60	60	76	62
Oil Consumption by Power Plants (million bbl/day)						
Power Plants	--	1.8	1.9	1.9	1.9	1.9
Coal Transportation	--	0.1	0.1	0.1	0.1	0.1
TOTAL	3.1	1.9	2.0	2.0	2.0	2.0

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[a] Results of EPA analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

Table 4D. IMPACTS ON FUELS IN 1990 WITH .90 PERCENT FGD RELIABILITY[a]

	Level of Control				
			-------- Full Control --------		Partial Control
	1975 Actual	Current Standards	90% Control With 40 ng/J Limit	90% Control Across Scrubber	240 ng/J Emission Limit
U.S. Coal Production (million tons)					
Appalachia	--	419	398	398	411
Midwest	--	348	387	387	374
Northern Great Plains	--	463	460	459	450
West	--	211	183	184	202
TOTAL	647	1441	1428	1428	1437
Western Coal Shipped East (million tons)	21	84	65	64	63
Oil Consumption by Power Plants (million bbl/day)					
Power Plants	--	1.8	2.1	2.1	1.9
Coal Transportation	--	0.1	0.1	0.1	0.1
TOTAL	3.1	1.9	2.2	2.2	2.1

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[a] Results of EPA analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

Table 5A. ECONOMIC IMPACTS IN 1990 WITH 100 PERCENT FGD RELIABILITY[a]
(1978 $)

	Level of Control			
		Full Control		
	Current Standards	90% Control With 340 ng/J Limit	90% Control With 240 ng/J Limit	90% Control Across Scrubber
Average monthly residential bills ($/month)	50.52	51.32	51.35	51.37
Incremental utility capital expenditures, cumulative 1976-1990 ($ billions)	--	2.6	2.4	2.5
Incremental annualized cost ($ billions)	--	1.9	2.0	2.1
Incremental cost of SO_2 reduction ($/ton)	--	1236	1041	1010

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[a] Results of EPA analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

Table 58. ECONOMIC IMPACTS IN 1990 WITH 100 PERCENT FGD RELIABILITY[a] (1978 $)

	Level of Control				
		Partial Control			
	Current Standards	240 ng/J Emission Limit	90% Control With 330 ng/J Max. Control	Sliding Scale With 90% Control in West	240 ng/J Std. With 90% Control in West
Average monthly residential bills ($/month)	50.52	51.18	51.04	51.30	51.28
Incremental utility capital expenditures, cumulative 1976-1990 ($ billions)	--	5.5	4.8	4.1	6.0
Incremental annualized cost ($ billions)	--	1.5	1.1	1.8	1.7
Incremental cost of SO_2 reduction ($/ton)	--	955	1099	1014	958

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[a] Results of EPA analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

Table 5C. ECONOMIC IMPACTS IN 1990 WITH 100 PERCENT FGD RELIABILITY[a]
(1978 $)

	Level of Control				
		------------- Partial Control ------------			
	Current Standards	90% Control With 150 ng/J Max. Control	90% Control With 240 ng/J Max. Control	Sliding Scale with 390 ng/J Limit	95% Control[b] With 520 ng/J Limit
Average monthly residential bills ($/month)	50.52	51.35	51.16	50.90	51.12
Incremental utility capital expenditures, cumulative 1976-1990 ($ billions)	--	6.4	5.5	5.1	5.5
Incremental annualized cost ($ billions)	--	1.8	1.4	0.7	1.3
Incremental cost of SO_2 reduction ($/ton)	--	1080	1090	2045	524

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[a] Results of EPA analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Modified FGD cost functions used.

Table 5D. ECONOMIC IMPACTS IN 1990 WITH 90 PERCENT FGD RELIABILITY[a] (1978 $)

		Level of Control		
		Full Control		Partial Control
	Current Standards	90% Control With 240 ng/J Limit	90% Control Across Scrubber	240 ng/J Emission Limit
Average monthly residential bills ($/month)	50.52	51.34	51.36	51.23
Incremental utility capital expenditures, cumulative 1976-1990 ($ billions)	--	0.0	0.2	4.7
Incremental annualized cost ($ billions)	--	2.1	2.1	1.6
Incremental cost of SO_2 reduction ($/ton)	--	1171	1103	1115

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[a] Results of EPA analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

Table 6A. SUMMARY OF 1995 IMPACTS WITH 100 PERCENT FGD RELIABILITY[a]

	Level of Control				
			Full Control		
	1975 Actual	Current NSPS	90% Control With 340 ng/J Limit	90% Control With 240 ng/J Limit	90% Control Across Scrubber
National Emissions (million tons SO_2)	18.6	23.7	20.5	19.8	19.5
New Plant Emissions[b] (million tons SO_2)	--	7.1	3.2	2.3	2.0
U.S. Coal Production (million tons)	647	1779	1765	1767	1768
Western Coal Shipped East (million tons)	21	122	59	77	77
Oil Consumption (million bbl/day)	3.1	1.3	1.7	1.7	1.7
Incremental Cumulative Capital Expenditures (1978 $ billion)	--	--	4.4	4.4	5.0
Incremental Annualized Cost (1978 $ billion)	--	--	4.1	4.3	4.3
Average Monthly Residential Bill (1978 $/month)	--	53.03	54.31	54.37	54.40
Total Coal Capacity (GW)	198	552	521	520	520

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Plants subject to the revised standards.

Table 6B. SUMMARY OF 1995 IMPACTS WITH 100 PERCENT FGD RELIABILITY[a]

	Level of Control					
			Partial Control			
	1975 Actual	Current MSPS	240 ng/J Emission Limit	90% Control With 330 ng/J Max. Control	Sliding Scale With 90% Control in West	240 ng/J Std. With 90% Control in West
National Emissions (million tons SO_2)	18.6	23.7	20.3	21.2	19.9	20.0
New Plant Emissions[b] (million tons SO_2)	--	7.1	3.2	4.3	2.5	2.8
U.S. Coal Production (million tons)	647	1779	1765	1762	1769	1767
Western Coal Shipped East (million tons)	21	122	73	79	92	73
Oil Consumption (million bbl/day)	3.1	1.3	1.6	1.5	1.6	1.6
Incremental Cumulative Capital Expenditures (1978 $ billion)	--	--	5.9	3.7	9.0	7.4
Incremental Annualized Cost (1978 $ billion)	--	--	3.3	2.6	4.0	3.7
Average Monthly Residential Bill (1978 $/month)	--	53.03	54.08	53.84	54.34	54.24
Total Coal Capacity (GW)	198	552	534	537	531	533

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[a] Results of joint EPA/DOE analysis completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Plants subject to the revised standards.

Table 6C. SUMMARY OF 1995 IMPACTS WITH 100 PERCENT FGD RELIABILITY[a]

	Level of Control					
			Partial Control			
	1975 Actual	Current NSPS	90% Control With 150 ng/J Max. Control	90% Control With 240 ng/J Max. Control	Sliding Scale With 390 ng/J Limit	95% Control With 520 ng/J Limit[c]
National Emissions (million tons SO_2)	18.6	23.7	20.0	20.8	22.8	18.2
New Plant Emissions[b] (million tons SO_2)	--	7.1	2.6	3.7	6.0	1.6
U.S. Coal Production (million tons)	647	1779	1762	1765	1765	1799
Western Coal Shipped East (million tons)	21	122	68	69	83	54
Oil Consumption (million bbl/day)	3.1	1.3	1.6	1.6	1.5	1.5
Incremental Cumulative Capital Expenditures (1978 $ billion)	--	--	8.1	5.7	3.6	7.2
Incremental Annualized Cost (1978 $ billion)	--	--	4.0	3.1	1.9	0.8
Average Monthly Residential Bill (1978 $/month)	--	53.03	54.33	54.04	53.64	53.31
Total Coal Capacity (GW)	198	552	531	534	537	542

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[a] Results of joint EPA/DOE analysis completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Plants subject to the revised standards.

[c] Modified FGD cost functions used.

Table 6D. SUMMARY OF 1995 IMPACTS WITH 90 PERCENT FGD RELIABILITY[a]

	Level of Control				
			------- Full Control	-------------	Partial Control
	1975 Actual	Current NSPS	90% Control With 40 ng/J Limit	90% Control Across Scrubber	240 ng/J Emission Limit
National Emissions (million tons SO_2)	18.6	23.7	20.1	19.8	20.5
New Plant Emissions[b] (million tons SO_2)	--	7.1	2.4	2.1	3.2
U.S. Coal Production (million tons)	647	1779	1761	1762	1760
Western Coal Shipped East (million tons)	21	122	79	81	74
Oil Consumption (million bbl/day)	3.1	1.3	1.8	1.8	1.6
Incremental Cumulative Capital Expenditures (1978 $ billion)	--	--	3.5	4.2	5.2
Incremental Annualized Cost (1978 $ billion)	--	--	4.6	4.6	3.5
Average Monthly Residential Bill (1978 $/month)	--	53.03	54.46	54.47	54.14
Total Coal Capacity (GW)	198	552	520	520	534

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[a] Results of joint EPA/DOE analysis completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

[b] Plants subject to the revised standards.

Table 7. SLUDGE GENERATED FROM UTILITY BOILERS[a]
(million tons/year dry basis)

NSPS Alternative	100% Reliability		90% Reliability	
	1990	1995	1990	1995
Current standard	17.7	23.0	--	--
90% control with 340 µg/J limit	33.2	55.1	--	--
90% control with 240 µg/J limit	33.3	53.7	32.2	52.1
90% control across scrubber	33.4	53.7	32.4	51.7
240 µg/J emission limit	27.4	41.5	26.1	39.3
90% control with 330 µg/J max control	25.7	38.1	--	--
Sliding scale with 90% control in West	29.0	47.3	--	--
240 µg/J standard with 90% control in West	28.8	43.5	--	--
90% control with 150 µg/J max control	31.5	49.6	--	--
90% control with 240 µg/J max control	28.4	43.4	--	--
Sliding scale with 390 ng/J Limit	25.5	39.5	--	--
95% control with 520 ng/J Limit	36.0	62.2	--	--

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[a] Results of joint EPA/DOE analysis completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.

TABLE 8. PRESENT VALUE OF INCREMENTAL UTILITY REVENUE REQUIREMENTS RELATIVE TO CURRENT STANDARDS[a]
(billions 1978 $)

NSPS Alternative	100% Reliability		90% Reliability	
	1990	1995	1990	1995
Current standard	--	--	--	--
90% control with 340 ng/J limit	21.9	41.4	--	--
90% control with 240 ng/J limit	21.8	43.4	23.5	46.2
90% control across scrubber	23.1	43.6	24.0	46.5
240 ng/J emission limit	16.5	33.0	17.9	34.7
90% control with 330 ng/J maximum control	12.9	25.8	--	--
Sliding scale with 90% control in West	20.1	39.7	--	--
240 ng/J standard with 90% control in West	18.9	37.3	--	--
90% control with 150 ng/J maximum control	20.7	40.0	--	--
90% control with 240 ng/J maximum control	15.8	31.2	--	--
Sliding scale with 390 ng/J limit	8.3	18.6	--	--
95% control with 520 ng/J limit[b]	14.7	10.4	--	--

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[a] Results of joint EPA/DOE analyses completed in November 1978 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively. Revenue requirements reflect total plant capital and operating costs including pollution control equipment.

[b] Modified FGD cost functions used.

[FR Doc. 78-34506 Filed 12-7-78; 9:31 am]

ENVIRONMENTAL PROTECTION AGENCY

■

PETROLEUM LIQUID STORAGE VESSELS

Proposed Standards and Notice of Hearing

SUBPART K and Ka

V-K, Ka-1

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 870-5]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Storage Vessels for Petroleum Liquids

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The proposed standards would limit emissions of hydrocarbons from new, modified, and reconstructed petroleum liquid storage vessels with a capacity greater than 151,416 liters (40,000 gallons). The standards implement the Clean Air Act and are based on a review of the current standards of performance which indicated that the technology for storage vessels has imporved and it is appropriate to revise the standards. The current standards for storage vessels require a single seal to close the space between the roof edge and tank wall on external and internal floating roof tanks. The intended effect of the proposed standard is to require double seals on external floating roof tanks for which construction is commenced after (date of proposal of the standards).

DATES: Comments must be received on or before June 19, 1978. A public hearing will be held on June 7, 1978; a notice is published elsewhere in this FEDERAL REGISTER regarding the time and place the hearing will be held.

ADDRESSES: Comments should be submitted to the Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, Attention: Mr. Jack R. Farmer. Public comments received and other documents used in the development of the proposed standards comprise the docket required by section 307(d) of the Clean Air Act. Included in the docket is the economic impact assessment of the proposed standards entitled "Financial and Economic Impacts of Proposed Standards of Performance for New Sources—Storage Vessels for Petroleum Liquids." The docket, numbered OAQPS-78-2, is available for public inspection and copying at the Public Information Reference Unit, Room 2922, 401 M Street SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT:

Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number 919-541-5271.

SUPPLEMENTARY INFORMATION:

SUMMARY OF PROPOSED STANDARDS AND IMPACTS

The proposed standards of performance would apply to storage vessels which have a capacity greater than 151,416 liters (40,000 gallons) and which are constructed after (proposal date of these standards). The proposed standards differ from the current standards in that they contain more stringent requirements for storage vessels which have external floating roofs or internal-floating-type covers. The current standards require that storage vessels containing a petroleum liquid with a true vapor pressure equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia) be equipped with a floating roof, a vapor recovery system, or equivalent. Storage vessels containing petroleum liquids with a true vapor pressure greater than 570 mm Hg (11.1 psia) are to be equipped with a vapor recovey system or its equivalent. The current standards remain in effect for those affected facilities which began construction, modification, or reconstruction after the applicable date of the current standards (March 8, 1974, for vessels with capacities between 40,000 and 65,000 gallons and June 11, 1973, for vessels with greater than 65,000 gallon capacity) and before (date of proposal of these standards). Retrofit of such facilities would not be required by the proposed standards.

The proposed standards would require the use of double seals on external floating roof storage vessels. The primary seal would have to be a metallic shoe seal or equivalent with a seal fabric having no holes, tears, or other openings. Gaps between the tank wall and the primary seal could not exceed 0.32 cm (⅛ in.) in width for a cumulative length of 60 percent of the circumference of the tank, 1.3 cm (½ in.) in width for a cumulative length of 30 percent of the circumference of the tank, and 3.8 cm (1½ in.) in width for a cumulative length of 10 percent of the circumference of the tank. The secondary seal would be required to completely cover the space between the roof edge and the tank wall. Gaps between the tank wall and the secondary seal could not exceed 0.32 cm (⅛ in.) in width for a cumulative length of 95 percent of the circumference of the tank, and 1.3 cm (½ in.) in width for a cumulative length of 5 percent of the circumference of the tank.

The proposal also specifies that the Administrator approves as equivalent technology the use of a nonmetallic resilient seal as the primary seal provided that the gaps between the tank wall and the primary seal do not exceed 0.32 cm (⅛ in.) in width for a cumulative length of 95 percent of the circumference of the tank and do not exceed 1.3 cm (½ in.) in width for a cumulative length of the remaining 5 percent of the circumference of the tank, and the gaps between the tank wall and the secondary seal used above the nonmetallic resilient seal do not exceed 0.32 cm (⅛ in.) in width over the entire circumference of the tank.

Since the current standards already require at least single seals on floating roof tanks, the maximum cost of the proposed standards would be the incremental cost of using a shoe seal instead of a nonmetallic resilient seal as the primary seal and of installing a second seal. These two costs are estimated to increase the cost of a new 61-meter (200-foot) diameter storage vessel by about 0.9 to 1.9 percent.

The proposed standards would have a positive impact on environmental quality. The estimated emission reduction attributed to the current standards is 80 percent. The proposed standards would further reduce emissions from a new storage vessel containing a petroleum liquid by about 75 percent. The total emission reduction, therefore, would be about 95 percent. The proposed standards would have no adverse environmental or energy impacts.

BACKGROUND

On March 8, 1974, under the authority of section 111 of the Clean Air Act, EPA promulgated standards of performance in Subpart K of 40 CFR Part 60 for hydrocarbon emissions from petroleum liquid storage vessels with a capacity greater than 151,416 liters (40,000 gallons). These standards require that new storage vessels containing petroleum liquids with a true vapor pressure greater than 570 mm Hg (11.1 psia) be equipped with a vapor recovery system or its equivalent. For petroleum liquids with a true vapor pressure equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), new storage vessels are required to be equipped with a floating roof (internal or external), a vapor recovery system, or equivalent. The primary intent of Subpart K was to prohibit the use of fixed roofs on new storage vessels. A floating roof or vapor recovery system has the potential for reducing emissions by 70 to 90 percent more than the reduction achieved with a fixed roof only.

An external floating roof tank consists of a welded or riveted cylindrical vessel equipped with a deck or roof which floats on the liquid surface and rises and falls with the liquid level in the tank. The liquid surface is completely covered by the roof except for the space between the roof and the wall. The current standards require that a sliding seal be attached to the roof to close the space between the roof edge and the tank wall. The seals in current use are metallic shoe seals or nonmetallic resilient seals (see Figures 1 and 2). For a storage vessel equipped to meet the current standards, emissions are primarily due to wind-induced hydrocarbon losses through the seal system. Seal losses increase if there is an improper fit between the seal and the tank wall or leakage through the fabric cover that is used to bridge the space between a shoe seal and the floating roof.

Although good maintenance and inspection programs may be effective in reducing emissions through a single seal, recent industry tests have indicated that reductions can be achieved by installing a second seal over the primary seal (see Figure 3). As improved technology is developed, section 111(b)(1)(B) of the Clean Air Act provides for revision of standards of performance. Since the promulgation of the current standards, the use of double seals on external floating roof tanks has been demonstrated and has been shown to significantly reduce emissions. The intent of the proposed standards is to require the use of double seals instead of single seals on external floating roof petroleum liquid storage vessels for which construction is commenced on or after (date of proposal of these standards).

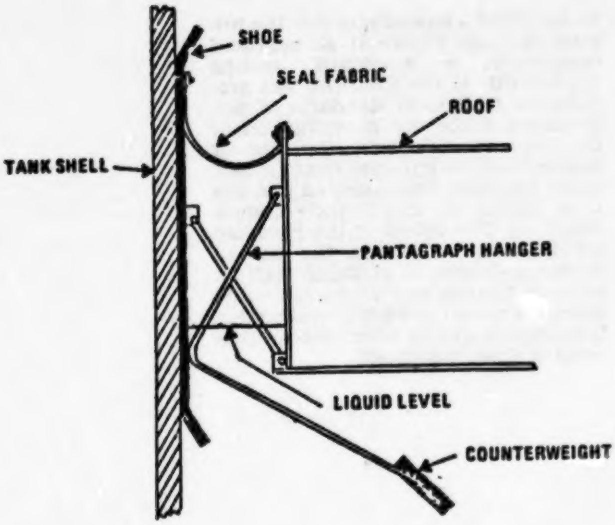
SHOE
SEAL FABRIC
ROOF
TANK SHELL
PANTAGRAPH HANGER
LIQUID LEVEL
COUNTERWEIGHT

Figure 1. Primary metallic shoe seal

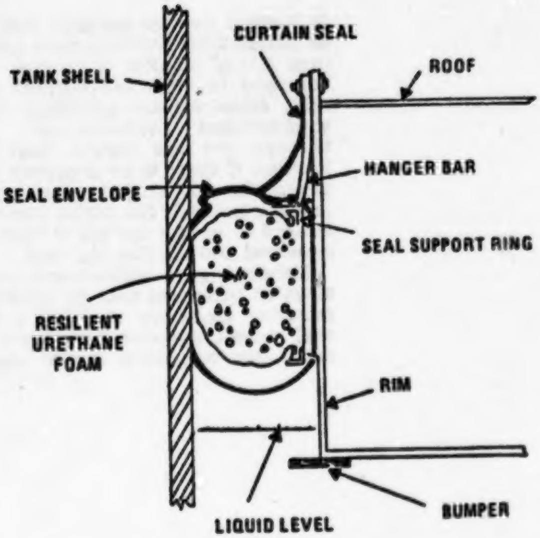
CURTAIN SEAL
TANK SHELL
ROOF
HANGER BAR
SEAL ENVELOPE
SEAL SUPPORT RING
RESILIENT URETHANE FOAM
RIM
LIQUID LEVEL
BUMPER

Figure 2. Primary nonmetallic resilient seal

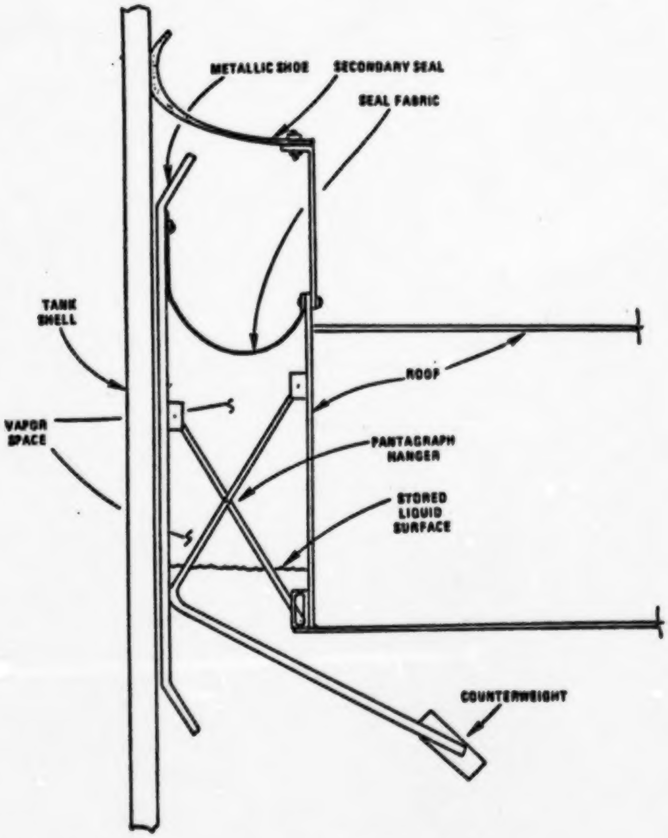
METALLIC SHOE
SECONDARY SEAL
SEAL FABRIC
TANK SHELL
ROOF
VAPOR SPACE
PANTAGRAPH HANGER
STORED LIQUID SURFACE
COUNTERWEIGHT

Figure 3. Metallic-shoe-type seal with secondary seal

The proposed standards are in terms of equipment specifications and maintenance requirements rather than mass emission rates. It is extremely difficult to quantify mass emission rates for petroleum liquid storage vessels because of the varying loss mechanisms and the number of variables affecting loss rate. Section 111(h)(1) of the Act provides that equipment standards may be established for a source category if it is not feasible to prescribe or enforce a standard which specifies an emission limitation. It also requires that an equipment standard include requirements to insure the proper operation and maintenance of the equipment. Therefore, the proposed standards contain certain monitoring requirements.

RATIONALE FOR PROPOSED STANDARDS

SELECTION OF THE SOURCE CATEGORY AND AFFECTED FACILITY

Section 111 of the Act directs the Administrator to establish standards of performance for new and modified stationary sources that may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare. EPA considers petroleum liquid storage vessels to be significant contributors to air pollution. Based on emission factors (*1, 2*) derived from equations in American Petroleum Institute Bulletins, current nationwide hydrocarbon emissions from petroleum liquid storage tanks are estimated to be about 750 Gg (or about 850,000 tons) per year. This represents about 4.5 percent of the estimated 1975 national hydrocarbon emissions from stationary sources. (*3*)

In a 1976 study of the petroleum refining industry,(*4*) EPA estimated that the growth rate of domestic petroleum demand would be about 2½ percent annually for the period 1974 to 1985. It is assumed that the growth rate of petroleum liquid storage tanks would be the same. Although this estimated growth rate is subject to change depending on the world energy situation and the nation's energy policy, growth in the construction of new petroleum liquid storage tanks is likely to continue at about this rate at least into the near future. All new petroleum storage tanks will be required by EPA's current standards of performance to have floating roofs, vapor recovery systems, or equivalent. Because petroleum liquid storage vessels are significant contributors to air pollution and it has been demonstrated that emissions from these vessels which are equipped with external floating roofs in compliance with the current standards can be reduced further by installation of double seals, petroleum liquid storage vessels have been selected for additional regulation. Petroleum liquid storage vessels for which construction was commenced before (date of proposal of these standards) are still subject to the existing standards of performance and those storage vessels equipped with external floating roofs are required to have single seals only.

SELECTION OF BEST TECHNOLOGY CONSIDERING COSTS

Measurement of emissions to the atmosphere from commercial size petroleum liquid storage vessels with external floating roofs using conventional measurement techniques is virtually impossible because the emissions are not confined. The proposed standards, therefore, are based primarily on studies conducted recently by Chicago Bridge and Iron (CBI) for Standard Oil of Ohio and Western Oil and Gas Association (*5*), (*6*), (*7*), (*10*), (*11*) on a 6-meter (20-foot) diameter test tank which was enclosed for the purpose of emission measurement. During the CBI studies, pressure drop measurements were made around the circumference of the tank on the windward and leeward sides. Emissions were measured under a variety of conditions to determine the impact of such factors as wind speed, the use of double seals, gap size between the seals and tank wall, shoe seal tightness, rim temperatures, and product vapor pressure on emission levels.

It was found that most hydrocarbon emission from storage vessels are due to wind-induced pressure losses. Relative to reference atmospheric pressure, pressure variations occur around the edges of the roof of a tank as a function of wind velocity and position of the roof. With respect to wind direction, the pressure is higher on the leeward side than on the windward side of the tank. The pressure differences on a tank roof are such that fresh air flows downward through the space between the tank wall and the seal on the leeward side, across the liquid surface along the circumference of the tank, and out the other side. The spaces are saturated with hydrocarbon vapors, which are carried out in the flow of air. The true vapor pressure of the liquid being stored, which determines the hydrocarbon concentration in the spaces between the seal and tank wall and the roof and liquid surface, and the type and condition of seals are other factors which were found to significantly influence emissions.

Figure 4 shows the effect of various types of seals and seal conditions on emission levels. The other two factors which were found to have the most impact on emissions—wind velocity and vapor pressure of the stored liquid—are held constant. Emission levels would deviate from those shown in the figure if one of these conditions were changed. As indicated in Figure 4, for both nonmetallic resilient seals and shoe seals, using a secondary seal above the primary seal and reducing the gaps between both the primary and the secondary seals and the tank wall significantly reduce the emissions resulting from wind-induced pressure losses. Using double seals reduces the impact of the size of the gap between the primary seal and the tank wall on emission levels, but reducing these gaps still has a positive effect.

The CBI test data in Figure 4 also indicate that when a nometallic resilkient seal is used as the primary seal and the secondary seal has a 1.3 cm (½ in.) gap for 5 percent of the circumference of the vessel, emissions are 5 times higher than when a shoe seal is used as the primary seal and the secondary seal has the same gaps. Based on these data, it is concluded that the use of a shoe seal achieves a greater reduction in emissions than the use of a nonmetallic resilient seal.

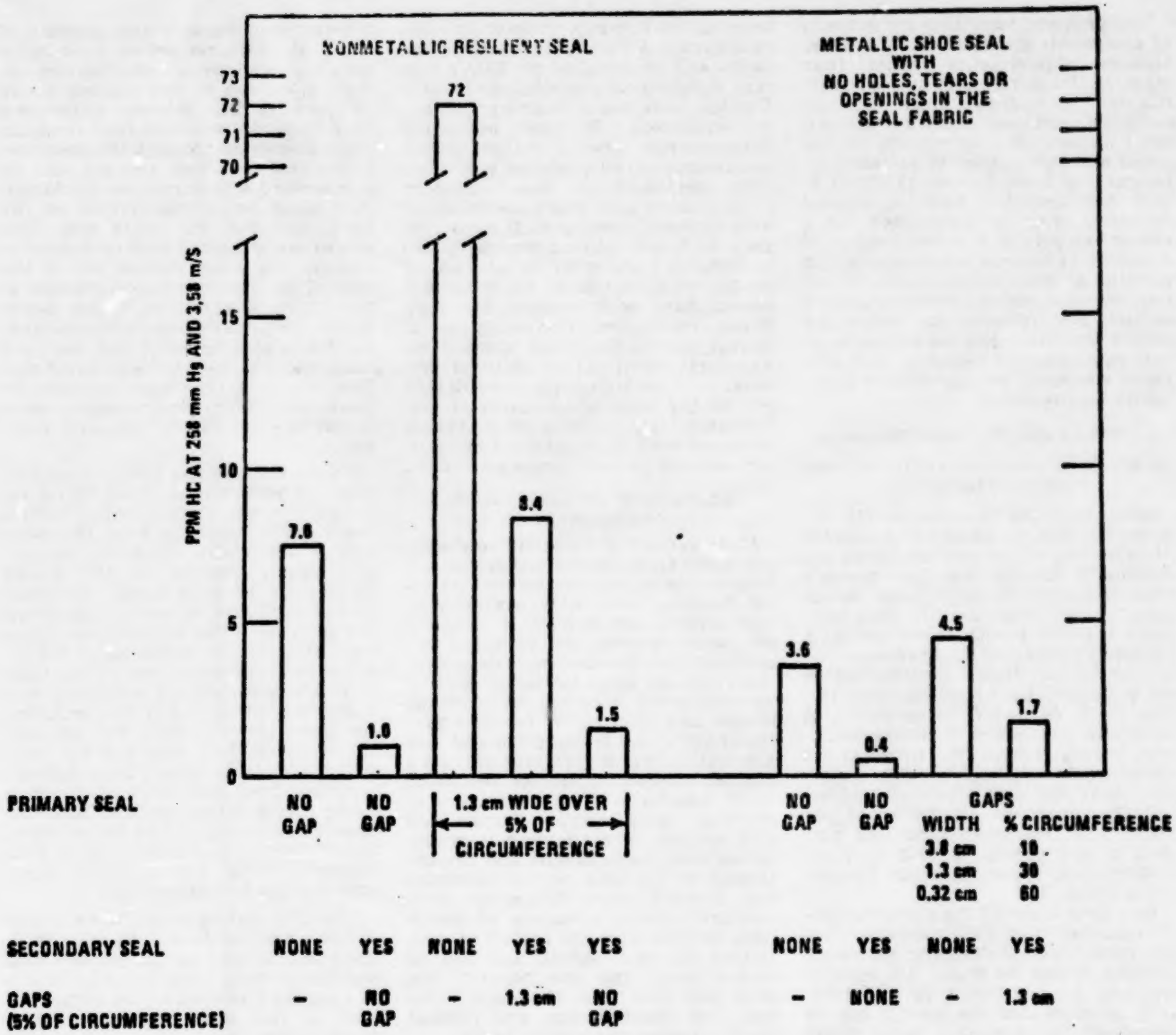

Figure 4. Emissions from CBI test tank with various seals.

It can also be seen in Figure 4 that a primary metallic shoe seal with no gap used in conjunction with a secondary seal with no gap achieves the lowest emission level. However, it is difficult to comply with a no gap requirement becuase in most cases the storage vessels are not perfectly round. A more viable regulatory approach would be to allow some small gaps between the seals and tank wall. From Figure 4 it can be seen that even with small gaps, the hydrocarbon emission level remains low. Consequently, the proposed standards contain certain gap requirements for both the primary and secondary seals.

For a shoe seal used as the primary seal, the permeability of the seal fabric used to bridge the space between the shoe seal and the floating roof can be an important factor affecting emission levels. The use of fabric with holes, tears, or openings increases leakage due to gas penetration through the fabric. Therefore, it is concluded that requiring the use of a metallic shoe seal with no holes, tears, or openings would result in reduced hydrocarbon emissions.

Costs must be considered in setting standards of performance under section 111. Since the current standards already require single seals on floating roof storage vessels the costs associated with the proposed standards are only the incremental costs of using a metallic shoe seal instead of a nonmetallic resilient seal as the primary seal and the costs of adding a secondary seal. For a new 61-meter (200-foot) diameter storage vessel, the total installed cost of a nonmetallic resilient seal is estimated to be approximately $20,000 to $33,000, and the total installed cost of a shoe seal is estimated to range from $28,000 to $41,000, or approximately $8,000 more than a nonmetallic resilient seal. The total annualized cost for a shoe seal is estimated to be about $2,400 more than that for a nonmetallic resilient seal. EPA is not aware of any situations where technological or economic considerations would preclude the installation of shoe seals in lieu of nonmetallic resilient seals during the construction of new petroleum storage vessels.

Adding a secondary seal is estimated to cost $12,600 to $19,000, and to increase total annualized costs by $4,000 to $5,800 if it is assumed that there are no savings due to retention of petroleum product. Total annualized costs would be reduced to between $1,700 and $5,400, however, if a savings in petroleum product is assumed. A range is estimated because the amount of petroleum product saved would depend on the true vapor pressure of the petroleum liquid and wind velocity.

The cost of a new 61-meter diameter storage vessel is estimated to be about $1,400,000 to $2,200,000. This cost includes the tank foundation, firewalls, connections to refinery pumps, lines, etc. Thus, using a shoe seal instead of a nonmetallic resilient seal as the primary seal and installing a secondary seal would increase the cost of a new storage vessel by only about 0.9 to 1.9 percent. By comparison, the increased cost for a new storage vessel to comply with the current standards is 12 to 25 percent. Therefore, the increased cost of complying with the proposed standards is considered to be reasonable and would not adversely affect the demand for new vessels. Since the additional cost would not reduce the demand for new vessels, the economic impact of the proposed standard on the manufacturers of storage vessels is small.

EPA also attempted to determine the impact of the proposed standards on nonmetallic resilient seal manufacturers; however, it was discovered that the materials for the seals are purchased by the storage vessel manufacturers who then fabricate and install the seals. Nearly all the storage vessel manufacturers have the expertise to install either metallic shoe seals or nonmetallic resilient seals with most manufacturers being indifferent to customer preference toward a certain type of seal. One manufacturer does stress its expertise with nonmetallic resilient seals; however, this emphasis has not caused disproportional sales of nonmetallic resilient seals over metallic shoe seals. Also, since the seals are fabricated on site, little or no extra capital would be needed to convert plant and equipment to produce a greater quantity of metallic shoe seals. In addition, storage vessel manufacturers generally do not maintain an inventory of nonmetallic resilient seal materials that would need to be liquidated.(12) Consequently, any shift towards more installation of metallic shoe seals caused by the proposed standards would have little impact on the storage vessel manufacturers.

Three companies in the United States currently supply the rubber casings and urethane foam necessary for the fabrication of the nonmetallic resilient seals. All three of these companies are highly diversified and the sale of nonmetallic resilient seal materials makes up only a small portion of their total sales. The average losses in sales of the three companies due to the proposed standard would range from about 0.5 to 1.4 percent of total sales.(12) Consequently, the economic impact on the nonmetallic resilient seal materials suppliers would be small.

Any difference in maintenance requirements for metallic shoe seals as compared with maintenance requirements for nonmetallic resilient seals could also impact the storage vessel purchasers. Generally, however, metallic shoe seals last longer and require less maintenance than nonmetallic resilient seals. *(12)* Therefore, this aspect of the proposed standards would have no adverse impact on the storage vessel purchasers.

The longer life of the average metallic shoe seal would also impact the vessel service companies. However, since replacing seals is only a small part of a vessel service company's business, the economic impact of the proposed standard would be small.

There is expected to be little, if any, economic impact on existing storage vessels as a result of modifications of existing vessels. The only change EPA is presently aware of which could potentially be considered a modification is a change in the petroleum liquid being stored. However, 40 CFR 60.14(e)(4) states that a change in fuel or raw material is not considered to be a modification if the existing facility was designed to accommodate that alternative use prior to the promulgation of standards of performance for that source type. There are likely to be few, if any, changes in the product being stored which a storage vessel was not originally designed to accommodate.

Using the emission control technology described in the preceding paragraphs—double seals; shoe seals as the primary seals; seal fabric with no holes, tears, or openings and narrow gap widths—would have a beneficial impact on environmental quality. Compared with the current standards, this technology would reduce hydrocarbon emissions from petroleum liquid storage vessels equipped with external floating roofs by 60 percent assuming a metallic shoe seal was used to meet the current standard, and up to 98 percent assuming a nonmetallic resilient seal was used to meet the current standard. These figures are based on Figure 4 and the assumption that the storage vessel is exposed to a wind velocity of 3.58 m/s (8 mph) and contains a petroleum liquid with a true vapor pressure of 258 mm Hg (5 psia). The percentage reduction would be expected to vary for different storage vessels depending on the wind speed and the true vapor pressure of the petroleum liquid being stored. There would be no adverse impacts on other environmental media. National energy requirements would actually be decreased very slightly since this technology would result in retention of petroleum products that would otherwise be lost as hydrocarbon emissions.

Consequently, the use of double seals employing a shoe seal with a seal fabric with no holes, tears, or openings as the primary seal, and having narrow gaps between both the primary and secondary seals and the storage vessel wall, has been selected as the best demonstrated technology, considering costs, for reducing emissions from petroleum liquid storage vessels. Thus, the proposed standards require either the use of this technology or technology demonstrated to be equivalent.

As can be observed in Figure 4, if a nonmetallic resilient seal is used as the primary seal and there are no gaps (i.e., gap widths of 0.32 cm or less) between the secondary seal and the storage vessel wall, emissions are approximately the same as when a shoe seal is used as the primary seal and the gaps on the secondary seal are as much as 1.3 cm (½ in.) for 5 percent of the circumference of the tank. The proposed regulation, therefore, states that the Administrator approves the use of a nonmetallic resilient seal as equivalent to a shoe seal for the primary seal if the secondary seal above the nonmetallic resilient seal has gaps no greater than 0.32 cm.

Instead of approving as equivalent technology the use of nonmetallic resilient seals in conjunction with secondary seals with no gaps greater than 0.32 cm, the standards of performance could require either the use of shoe seals or the use of nonmetallic resilient seals with the more stringent gap requirement for nonmetallic resilient seals. If the standard were written in this way, nonmetallic resilient seals would always be required to meet the more stringent gap requirement. It is possible, however, that improvements can be made to nonmetallic resilient seals to make them equivalent to metallic shoe seals without meeting a more stringent gap requirement. It is also possible that other seals can be developed that would be equivalent to metallic shoe seals. The proposed standards, therefore, provide maximum flexibility for manufacturers to make improvements in nonmetallic resilient seals or other types of seals and demonstrate their equivalency to metallic shoe seals.

SELECTION OF MISCELLANEOUS REQUIREMENTS

The current standards of performance do not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer. These vessels were exempted because many of them are normally bolted for purposes of mobility. The proposed standards of performance, however, would apply to storage vessels at drilling and production facilities if the vessels are larger than 151,416 liters (40,000 gallons). Bolted vessels larger than the cut-off size would not be exempt because they are no different from other large storage vessels being covered with regard to emissions, control technology, or costs.

The definition of "petroleum refinery" has been expanded in both Subparts K and Ka to include extracting. This change is being made to ensure that the definition covers all activities at a petroleum refinery. "Extracting" was not purposely excluded in Subpart K and its addition should not change the impact of the standard.

SELECTION OF TESTING, MONITORING, AND RECORDKEEPING REQUIREMENTS

The proposed standards include a section on testing (section 60.114a) for determining compliance with the gap requirements. The current standards of performance do not have a comparable testing section because they do not contain gap requirements. Performance tests for most sources subject to Part 60 are required within 60 days after achieving the maximum production rate. The maximum production rate for a storage vessel would be the filling of the vessel with petroleum liquid. The proposed standards for storage vessels provide the option of doing the performance test before a tank is filled with petroleum liquid. This is based on the reasoning that the gaps between a primary seal and the tank wall have to be measured when the secondary seal is not in place when doing a performance test. This means that the tank could not contain petroleum liquid, since the secondary seal is required by the standard to cover the primary seal when the tank is in operation. The gaps for the primary seal would be most easily measured during the construction of the tank before the secondary seal is installed. If the owner or operator chose to do the measurements on the primary seal after the tank has been filled with petroleum liquid, it would be necessary to empty the tank and remove the secondary seal. The secondary seal gaps, on the other hand, could be measured when the tank is filled with petroleum liquid. The proposed standards would require that this performance test be repeated every five years.

The proposed standards would require that the distance between the seals and the tank wall be measured while the floating roof is placed at different levels. This could be done by putting different quantities of water into the tank before the tank is filled with petroleum liquid. Measuring the gaps at different levels is required because the floating roof would be located at different levels while the tank is in normal operation. The proposed standards would also require that the gaps be measured around the circumference of the tank. For each gap size, the distances around the tank which have that gap size would need to be accumulated. Gaps would be measured with a probe having a diameter equivalent to one of the gap widths specified in the standard. In the process of measuring gaps, those gap widths which are between two sizes specified in the standards would be considered equivalent to the larger of the two sizes. For example, a gap between 0.32 cm (⅛ in.) and 1.3 cm (½ in.) in width would be considered as 1.3 cm (½ in.).

Most of the monitoring and recordkeeping requirements in the proposed standards (sections 60.115a (a), (b), (c), and (d)) are the same as the ones in the current standards. An additional requirement is proposed to allow for routine inspection of the primary seal between performance tests. Under this requirement the secondary seal would allow easy insertion of probes in at least four locations for measuring gaps in the primary seal. This would allow for inspection of the primary seal without removing the secondary seal which would make emptying the tank unnecessary. The tank, therefore, would have to be emptied only during performance tests and routine maintenance of the secondary seal.

MISCELLANEOUS

In accordance with section 117 of the Act, publication of these proposed standards was preceded by consultation with independent experts and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues and record keeping requirements.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173 of the Act requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source, as defined in section 171(3). In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology for all pollutants regulated under the Act. The term "best available control technology" (BACT), as defined in section 169(3), means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), costs must be accorded far less weight in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Economic impact assessment: An economic impact assessment has been prepared as required under section 317 of the Act and is included in the docket.

Dated: May 2, 1978.

Douglas M. Costle,
Administrator.

References

(*1*) "Evaporation Loss from Floating Roof Tanks," American Petroleum Institute Bulletin 2517, February 1962.

(*2*) "Control of Hydrocarbon Emissions from Petroleum Liquids," EPA-600/2-75-042, September 1975.

(*3*) "Control of Volatile Organic Emissions from Existing Stationary Sources—Volume I: Control Methods for Surface—Coating Operations," EPA-450/2-76-028, November 1976.

(*4*) "Economic Impact of EPA's Regulations on the Petroleum Refining Industry," EPA-230/13-76-004, Part II, Section E, p. II-4.

(*5*) "SOHIO/CBI Floating Roof Emission Test Programs," Final Report, Chicago Bridge & Iron Co., November 18, 1976.

(*6*) "SOHIO/CBI floating roof Emission Test Program," Supplemental Report, Chicago Bridge & Iron Co., February 15, 1977.

(*7*) "Western Oil and Gas Association Metallic Sealing Ring Emission Test Program," Interim Report, Chicago Bridge & Iron, January 18, 1977.

(*8*) Ball, D. A., Putman, A. A., and Luce, R. G., "Evaluation of Methods for Measuring and Controlling Hydrocarbon Emissions from Petroleum Storage Tanks," U.S. EPA-450/13-76-036, November 1976.

(*9*) "Hydrocarbon Emissions From Floating Roof Storage Tanks," Prepared for the Western Oil & Gas Association by Engineering-Science, Inc., January 1977.

(*10*) Western Oil and Gas Association Metallic Sealing Ring Emission Test Program, Supplemental Report, Chicago Bridge & Iron, June 30, 1977.

(*11*) Letter, from Royce J. Laverman to Mr. R. K. Burr, October 11, 1977.

(*12*) "Financial and Economic Impacts of Proposed Standards of Performance for New Sources—Storage Vessels for Petroleum Agency," Draft Report, Energy and Environmental Analysis, Inc., August 1977.

It is proposed that 40 CFR Part 60 be amended by revising § 60.11(a) of Subpart A, by revising the heading and amending §§ 60.110 and 60.111 of Subpart K, and by adding a new Subpart Ka as follows:

1. § 60.11(a) is revised to read as follows:

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by § 60.8, unless otherwise specified in the applicable standard.

2. The heading for Subpart K is revised to read as follows:

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids Constructed Prior to (Date of Proposal of These Standards)

3. Paragraphs (c)(1) and (c)(2) of § 60.110 are revised to read as follows:

§ 60.110 Applicability and designation of affected facility.

* * * * *

(c) * * *

(1) Has a capacity greater than 151,416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to (date of proposal of these standards).

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to (date of proposal of these standards).

* * * * *

4. Paragraph (c) of § 60.111 is revised to read as follows:

§ 60.111 Definitions.

* * * * *

(c) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricant, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

5. A new Subpart Ka is added to read as follows:

Subpart Ka—Standards of Performance for Storage Vessels for Petroleum Liquids Constructed on or After (Date of Proposal of These Standards)

Sec.
60.110a Applicability and designation of affected facility.
60.111a Definitions.
60.112a Standard for hydrocarbons.
60.113a Equivalent equipment.
60.114a Testing and procedures.
60.115a Monitoring of operations.

Authority: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

§ 60.110a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,416 liters (40,000 gallons) and for which construction is commenced after (date of proposal of these standards).

§ 60.111a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Storage vessel" means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of

$0.0044 kg/m^3$ (15 $lb/in.^2$ gauge) without emissions to the atmosphere except under emergency conditions,

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in A.S.T.M. D396-69, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in A.S.T.M. D2880-71, or diesel fuel oils Nos. 2-D and 4-D as specified in A.S.T.M. D975-68.

(c) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) "Hydrocarbon" means any organic compound consisting predominantly of carbon and hydrogen.

(f) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(h) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM-D-323-58 (reapproved 1968).

§ 60.112a Standard for hydrocarbons.

(a) The owner or operator of any storage vessel which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), shall equip the storage vessel with one of the following:

(1) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and roof edge. Except during initial tank fill, performance tests, or when the tank is completely emptied, the roof is to be floating on the liquid, i.e. off the roof leg supports, at all times. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal.

(i) The primary seal is to be a metallic shoe seal or equivalent as provided in § 60.113a(b), and is to meet the following requirements:

(A) Gaps between the tank wall and the primary seal are not to exceed 0.32 cm (⅛ in.) in width for a cumulative length of 60 percent of the circumference of the tank, are not to exceed 1.3 cm (½ in.) in width for a cumulative length of the next 30 percent of the circumference of the tank, and are not to exceed 3.8 cm (1½ in.) in width for a cumulative length of the remaining 10 percent of the circumference of the tank. No gap between the tank wall and the primary seal shall exceed 3.8 cm (1½ in.). No continuous gap greater than 0.32 cm (⅛ in.) shall exceed 10 percent of the circumference of the tank.

(B) One end of the shoe seal is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in.) above the stored liquid surface.

(C) There are to be no holes, tears, or other openings in the shoe or seal fabric.

(ii) The secondary seal is to meet the following requirements:

(A) Gaps between the tank wall and the secondary seal are not to exceed 0.32 cm (⅛ in.) in width for a cumulative length of 95 percent of the circumference of the tank, and are not to exceed 1.3 cm (½ in.) in width for a cumulative length of the remaining 5 percent of the circumference of the tank. No gap between the tank wall and the secondary seal shall exceed 1.3 cm (½ in.).

(B) The secondary seal is to be installed above the primary seal so that the space between the roof edge and tank wall is completely covered, except as provided in paragraph (a)(1)(ii)(A) of this section.

(C) There are to be no holes, tears, or other openings in the seal or in any seal fabric.

(iii) All openings in the roof except for automatic bleeder vents and rim space vents are to provide a projection below the liquid surface and are to be equipped with a cover, seal, or lid. The cover, seal, or lid is to be in a closed (i.e. no visible gap) position at all times except when the device is in actual use. Automatic bleeder vents are to be closed at all times except whe the roof is floated off or landed on the roof leg supports and rim vents are to be set to open only when the roof is being floated off the roof leg supports.

(iv) Any emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening, or equivalent as provided in § 61.113a.

(2) A fixed roof container with an internal-floating-type cover which is equipped with a closure seal between the tank wall and roof edge. All openings, except stub drains, are to be equipped with a cover, seal, or lid. The cover, seal, or lid is to be in a closed position at all times except when the device is in actual use. Automatic bleeder vents are to be closed at all times except when the roof is floated off or landed on the roof leg supports. Rim vents, if provided, are to be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

(3) A vapor recovery system, capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel, and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3), as provided in § 61.113a.

(b) The owner or operator of any storage vessel which contains a petroleum liquid which, as stored, has a true vapor pressure greater than 570 mm Hg (11.1 psia), shall equip the storage vessel with:

(1) A vapor recovery system, capable of collecting all organic vapors and gases discharged, and a vapor return or disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere; or

(2) Equivalent as provided in § 60.113a.

§ 61.113a Equivalent equipment.

(a) Upon written application from an owner or operator, the Administrator may approve use of equipment which has been demonstrated to his satisfaction to be equivalent in terms of reducing hydrocarbon emissions to the atmosphere to that prescribed for compliance with a specific paragraph of this subpart.

(b) A nonmetallic resilient seal is approved as equivalent to the shoe seal required by § 61.112a(a)(1)(i) if the gaps between the tank wall and the primary seal do not exceed 0.32 cm (⅛ in.) in width for a cumulative length of 95 percent of the circumference of the tank and do not exceed 1.3 cm (½ in.) in width for a cumulative length of the remaining 5 percent of the circumference of the tank and the gaps between the tank wall and the secondary seal used above the nonmetallic resilient seal do not exceed 0.32 cm (⅛ in.) over the entire circumference of the tank.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.114a Testing and procedures.

(a) Except as provided in § 60.8(b), compliance with the standard prescribed in § 60.112(a) shall be determined as follows:

(1) The owner or operator of any storage vessel subject to this Subpart which has an external floating roof shall meet the following requirements:

(i) Determine the gap widths between the primary seal and the tank wall and the secondary seal and the tank wall, and furnish the Administrator with a written report of the results. This shall de done either before, or within 60 days after, the storage vessel is initially filled with petroleum liquid, at least once every five years thereafter, and at other times as may be required by the Administrator under section 114 of the Act. The gap widths shall be determined according to the following procedures:

(A) Measure the gaps at various roof levels, including the lowest level of the roof legs, the maximum roof height, and six approximately equidistant points between these two levels.

(B) Measure the gaps continuously around the circumference of the tank and determine the accumulated distance for each gap width.

(C) Measure the gaps with probes of diameter equal to each gap width specified in §§ 60.112a(a)(1) (i)(A) and (ii)(A). A gap is deemed to exist under the following conditions:

(*1*) For a primary seal, the probe is to touch the liquid surface without forcing, and

(*2*) For a secondary seal, the probe is to touch the primary seal without forcing.

(D) Tabulate the gap widths: gaps less than or equal to 0.32 cm (⅛ in.) are to be considered equivalent to 0.32 cm (⅛ in.), gaps greater than 0.32 cm (⅛ in.) but less than or equal to 1.3 cm. (½ in.) are to be considered to be equivalent to 1.3 cm (½ in.), and gaps greater than 1.3 cm (½ in.) but less than or equal to 3.8 cm (1½ in.) are to be considered equivalent to 3.8 cm (1½ in.).

(ii) Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.

[Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414)].

§ 60.115a. Monitoring of operations.

(a) The owner or operator of any storage vessel to which this subpart applies shall for each storage vessel maintain a file of each type of petroleum liquid stored, of the typical Reid vapor pressure of each type of petroleum liquid stored, and of the dates of storage. Dates on which the storage vessel is empty shall be shown.

(b) The owner or operator of any storage vessel to which this subpart applies shall for each storage vessel determine and record the average monthly storage temperature and true vapor pressure of the petroleum liquid stored at such temperature if:

(1) The petroleum liquid has a true vapor pressure, as stored, greater than 26 mm Hg (0.5 psia) but less than 78 mm Hg (1.5 psia) and is stored in a storage vessel other than one equipped with an external floating roof, an interval-floating-type cover, a vapor recovery system or their equivalents; or

(2) The petroleum liquid has a true vapor pressure, as stored, greater than 470 mm Hg (9.1 psia) and is stored in a storage vessel other than one equipped with a vapor recovery system or its equivalent.

(c) The average monthly storage temperature is an arithmetic average calculated for each calendar month, or portion thereof if storage is for less than a month, from bulk liquid storage temperatures determined at least once every 7 days.

(d) The true vapor pressure is to be determined by the procedure in API Bulletin 2517. This procedure is dependent upon determination of the storage temperature and the Reid vapor pressure, which requires sampling of the petroleum liquids in the storage vessels. Unless the Administrator requires in specific cases that the stored petroleum liquid be sampled, the true vapor pressure may be determined by using the average monthly storage temperature and the typical Reid vapor pressure. For those liquids for which certified specifications limiting the Reid vapor pressure exist, that Reid vapor pressure may be used. For other liquids, supporting analytical data must be made available on request to the Administrator when typical Reid vapor pressure is used.

(e) In order that the primary seal may be routinely inspected, the secondary seal is to allow easy insertion of probes up to 3.8 cm (1½ in.) in diameter in at least four locations to measure gaps in the primary seal on storage vessels equipped with external floating roofs.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414)).

[FR Doc. 78-13380 Filed 5-17-78; 8:45 am]

[6560-01]

[40 CFR Part 60]

[FRL 895-4]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Public Hearing on Proposed Standards for Petroleum Liquid Storage Vessels

AGENCY: Environmental Protection Agency.

ACTION: Hearing on proposed rule.

SUMMARY: This document announces a public hearing on the standards of performance for petroleum liquid storage vessels which are proposed in this issue of the FEDERAL REGISTER.

DATES: Hearing Date: Wednesday, June 7, 1978. See *Supplementary Information* for additional information.

ADDRESSES: Hearing held: Room 3906, Waterside Mall, 401 M Street SW., Washington, D.C. See *Supplementary Information* for additional information.

FOR FURTHER INFORMATION CONTACT:

Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: In accordance with section 307(d)(5) of the Clean Air Act, a public hearing on the standards of performance for petroleum liquid storage vessels which are proposed in this issue of the FEDERAL REGISTER will be held as follows:

DATE: Wednesday, June 7, 1978.

PLACE: Room 3906, Waterside Mall, 401 M Street SW., Washington, D.C.

TIME: 9:00 a.m.

PURPOSE: Interested persons will be provided the opportunity for oral presentation of data, views, or arguments concerning the proposed standards of performance for petroleum liquid storage vessels. The hearing is open to the public.

Persons wishing to make oral presentations, which will be limited to 15 minutes each, or to attend the hearing should notify EPA by May 31 by contacting Ms. Mary Jane Clark, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statements should be addressed to Mr. Jack R. Farmer at the address above.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at the U.S. Environmental Protection Agency's Public Information Reference Unit, Room 2922, Waterside Mall, 401 M Street SW., Washington, D.C. 20460 (Docket Number OAQPS-78-2).

Dated: May 9, 1978.

EDWARD F. TUERK,
Acting Assistant Administrator for Air and Waste Management.

[FR Doc. 78-13014 Filed 5-17-78; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 870-5]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Storage Vessels for Petroleum Liquids

Correction

In FR Doc. 78-13380 appearing at page 21616 in the issue for Thursday, May 18, 1978, the date given for the receipt of comments now reading "June 19, 1978" should have read "July 17, 1978".

ENVIRONMENTAL PROTECTION AGENCY

■

PRIMARY ALUMINUM INDUSTRY

Standards of Performance for New Stationary Sources; Public Hearing

SUBPART S

V-S-1

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 915-5]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Primary Aluminum Industry

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: The proposed amendments would require primary aluminum plant performance tests to be conducted at least once each month, allow potroom emissions to be above the level of the current standard (but not above a higher limit of 1.25 kg/Mg (2.5 lb/ton)) if an owner or operator can establish that the emission control system was properly operated at the time the excursion above the current standard occurred, revise the reference method for determining fluoride emissions from potroom roof monitors, and clarify some provisions in the existing standard. These amendments are being proposed in response to arguments raised by four aluminum companies who filed petitions for review of the standard of performance. The intended effect of the proposed amendments is to account for the inherent variability of fluoride emissions from the aluminum reduction process and to require monitoring of fluoride emissions to insure proper operation and maintenance of the pollution control systems.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before November 20, 1978. *Public hearing.* The public hearing will be held on October 16, 1978, beginning at 9:30 a.m. and ending at 4:30 p.m. *Request to speak at hearing.* Persons wishing to attend the hearing or present oral testimony should contact EPA by October 11, 1978.

ADDRESSES: *Comments.* Comments should be submitted to Jack R. Farmer, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711.

Public hearing. The public hearing will be held at Waterside Mall, Room 3906, 401 M Street SW., Washington, D.C. 20460. Persons wishing to present oral testimony should notify Mary Jane Clark, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

Standard support document. The support document for the proposed amendments may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711, telephone 919-541-2777. Please refer to Primary Aluminum Background Information: Proposed Amendments (EPA-450/2-78-025a).

Docket. The docket, number OAQPS-78-10, is available for public inspection and copying at the EPA Central Docket Section (A-130), Room 2903B, Waterside Mall, 401 M Street SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION:

PROPOSED AMENDMENTS

It is proposed to amend Subpart S—Standards of Performance for Primary Aluminum Plants by requiring that performance tests be performed at least once each month during the life of an affected facility. Previously, performance tests were required only as provided in 40 CFR 60.8(a) (i.e., within 60 days after achieving the maximum production rate, but not later than 180 days after initial start- up and at other times as may be required by the Administrator under section 114 of the Clean Air Act). The proposed amendments would also allow potroom emissions to be above the level of the current standard (0.95 kg/Mg (1.9 lb/ton) for prebake plants and 1.0 kg/Mg (2.0 lb/ton) for Soderberg plants), but not above 1.25 kg/Mg (2.5 lb/ton), if an owner or operator can establish that the emission control system was properly operated and maintained at the time the excursion above the current standard occurred. Emissions may not be above 1.25 kg/Mg under any condition. Other amendments would (1) clarify Reference Method 14 procedures; (2) clarify the definition of "potroom group;" (3) replace English and metric units of measure with the International System of Units (SI); (4) allow the owner or operator of a new facility to apply to the Administrator for an exemption from the monthly testing requirement for primary and anode bake plant emissions; and (5) clarify the procedure for determining the rate of aluminum production for fluoride emission calculations.

BACKGROUND

A standard of performance for new primary aluminum plants was promulgated on January 26, 1976 (41 FR 3826), and shortly thereafter petitions for review were filed by four U.S. aluminum companies. The principal argument raised by the petitioners was that the standard was too stringent and could not be consistently complied with by modern, well-controlled facilities. (Facilities which commenced construction prior to October 23, 1974, are not affected by the standard.) Following discussions with the petitioning aluminum companies, EPA conducted an emission test program at the Anaconda Aluminum Co. plant in Sebree, Ky. The Sebree plant is the newest primary aluminum plant in the United States, and its emisssion control system conforms with what EPA has defined as the best technological system of continuous emission reduction for new facilities. The purpose of the test program was to aid EPA in its reevaluation of the standard by expanding the emission data base. The test results were available in August of 1977 and indicated that there is some probability that the result of a performance test conducted at a modern, well-controlled plant would be above the existing standard. EPA has concluded that this justifies revising the standard.

RATIONALE

EPA's decision to amend the existing standard is based primarily on the results of the Sebree test program. The test results may be summarized as follows: (1) The measured emissions were variable, ranging from 0.43 to 1.37 kg/Mg (0.85 to 2.74 lb/ton) for single test runs; and (2) emission variability appeared to be inherent in the production process and beyond the control of plant personnel. Since the Sebree plant represents the latest technology for the aluminum industry, EPA expects that new plants covered by the standard may also exhibit emission variability.

An analysis performed by EPA on the results of the nine Sebree test runs indicates that there is about an 8-percent probability that a performance test would violate the current standard. (A performance test is defined in 40 CFR 60.8(f) as the arithmetic mean of three separate test runs, except in situations where a run must be discounted or canceled and the Administrator approves using the arithmetic mean of two runs.) The petitioners have estimated chances of violation ranging from about 2.5 to 10 percent. Although the Sebree data base is not large enought to permit a thorough statistical analysis, EPA believes it is adequate to demonstrate a need for revising the current standard.

EPA considered a number of possible solutions to the emission variability problem including raising the level of the current standard, allowing a certain number of monthly tests to exceed the current standard based on an expected failure rate, and specifying an equipment standard in place of the current emission standard. These and other possible solutions were rejected because they did not satisfy the following criteria: The revised standard (1) must be enforceable, (2) must provide for the variability of emissions, and (3) must not allow emission levels to be higher than indicated by the Sebree plant, which employs the best system of emission reduction.

The solution EPA proposes is to amend Subpart S to allow a performance test to be above the current standard provided the owner or operator submits to EPA a report clearly demonstrating that the emission control system was properly operated and maintained during the excursion above the standard. The report would be used as evidence that the high emission level resulted from random and uncontrollable emission variability, and that the emission variability was entirely beyond the control of the owner or operator of the affected facility. Under no circumstances, however, would performance test results be allowed above 1.25 kg/Mg (2.5 lb/ton). EPA believes that emissions from a plant equipped with the proper control system which is properly operated and maintained would be below 1.25 kg/Mg at all times.

Within 15 days of receipt of the results of a performance test which fall between the current standard and 1.25 kg/Mg, the owner or operator of the affected facility would be required to submit a report to the Enforcement Division of the appropriate EPA Regional Office indicating that all necessary control devices were on-line and operating properly during the performance test, describing the operation and maintenance procedures followed, and setting forth any explanation for the excess emissions. EPA requests comments on additional criteria to be used by the Regional Offices to determing whether the control devices were properly operated and maintained during the performance test.

The proposed amendments would also require, following the initial performance test required under 40 CFR 60.8(a), additional performance testing at least once each month during the life of the affected facility. During visits to existing plants, EPA personnel have observed that the emission control systems are not always operated and maintained as well as possible. EPA believes that good operation and maintenance of control systems is essential and expects the monthly testing requirement to help achieve this goal. The Administrator has the authority under section 114 of the Clean Air Act to require additional testing if necessary.

It is important to emphasize that the following operating and maintenance procedures are exemplary of good control of emissions and should be implemented at all times: (1) Hood covers should fit properly and be in good repair; (2) if equipped with an adjustable air damper system, the hood exhaust rate for individual pots should be increased whenever hood covers are removed from a pot (the exhaust system should not be overloaded by placing too many pots on high exhaust); (3) hood covers should be replaced as soon as possible after each potroom operation; (4) dust entrainment should be minimized during materials handling operations and sweeping of the working aisles; (5) only tapping crucibles with functional aspirator air return systems (for returning gases under the collection hooding) should be used; and (6) the primary control system should be regularly inspected and properly maintained. EPA believes that the proposed amendments are clearly achievable provided the control system is properly designed and installed and, as a minimum, the six procedures noted above are emplemented.

The proposed amendments affect not only prebake designs, such as the Sebree plant, but also Soderberg plants. Available data for existing plants indicate that Soderberg and prebake plants have similar emission variability. Thus, EPA feels justified in extrapolating its conclusions about the Sebree prebake plant to cover Soderberg designs. It is unlikely that any new Soderberg plant will be built due to the high cost of emission control for these designs. However, existing Soderberg plants may be modified to such an extent that they would be subject to these regulations.

Under the proposed amendments anode bake plants would be subject to the monthly testing requirement, but emissions would not be allowed under any circumstances to be above the level of the current bake plant standard. Since there is no evidence that bake plant emissions are as variable as potroom emissions, there is no need to excuse excursions above the bake plant standard.

The proposed amendments would allow the owner or operator of a new plant to apply to the Administrator for an exemption from the monthly testing requirement for the primary control system and the anode bake plant. EPA believes that the testing of these systems as often as once each month may be unreasonable given that (1) The contribution of primary and bake plant emissions to the total emission rate is minor, averaging about 2.5 and 5 percent, respectively; (2) primary and bake plant emissions are much less variable than secondary emissions; and (3) the cost of primary and bake plant emissions sampling is high. An application to the Administrator for an exemption from monthly testing would be required to include (1) evidence that the primary and bake plant emissions have low variability; (2) an alternative testing schedule; and (3) a representative value for primary emissions to be used in total fluoride emission calculations.

EPA estimates the costs associated with monthly performance testing to average about $4,000 for primary tests, $5,000 for secondary tests, and $4,000 for bake plant tests. These estimates assume that (1) Testing would be performed by plant personnel; (2) each monthly performance test would consist of the average of 3 24-hour runs; (3) sampling would be performed by two crews working 13-hour shifts; (4) primary control system sampling would be performed at a single point in the stack; and (5) Sebree inhouse testing costs would be representative of average costs for other new plants. Although these assumptions may not hold for all situations, EPA believes they provide a representative estimate of what testing costs would be for new plants.

Also amended is the procedure for determining the rate of aluminum production. Previously, the rate was based on the weight of metal tapped during the test period. However, since the weight of metal tapped does not always equal the weight of metal produced, undertapping or overtapping during a test period would result in erroneous porduction rates. EPA believes it would be more reasonable to judge the weight of metal produced according to the average weight of metal tapped during a 30-day period (720 hours) prior to and including the test date. The 3-day period would allow for overtapping and undertapping to average out, and this would give a more accurate estimate of the true production rate.

Other amendments would (1) clarify the definition of potroom group to cover situations where two potroom segments are ducted to a common control system; (2) incorporate use of the International System of Units (SI); and (3) make minor editorial changes in the regulations.

METHOD 14

The proposed amendments to Reference Method 14 would update the test method to reflect EPA's experiences at the Sebree test program. Also, the amendments would make Method 14 consistent with recent revisions of Methods 1 through 8 (42 FR 41754). The intended effect of the proposed amendments is to clarify testing proce dures and to improve the reliability of the test method.

The principal amendments would be as follows: (1) More detailed anemometer specifications and calibration procedures would be delineated; (2) a performance check of each anemometer and each recorder (or counter) would be required following each test series (i.e., following each series of test runs as required for a performance test under 40 CFR 60.8(f)); (3) data adjustment procedures would be included for anemometers and recorders (or counters) that fail the performance check; (4) to be consistent with the new definition of "potroom group" more specific guidelines would be included for both the location of the sampling manifold and the number and location of the propeller anemometers; (5) for convenience, each Method 14 test run could be divided into "sub-runs"; (6) the use of a separate Method 13 train for each sub-run would be allowed, provided that the sampling nozzle size for all trains is the same; (7) a procedure would be included for calculating the fluoride concentration when more than one sampling train is used; (8) the tester would be allowed greater freedom as to the method by which velocity estimates are made for setting isokinetic flow; (9) the limits of acceptable isokinetic results would be more clearly defined, and a data adjustment procedure would be included for cases where the results are outside these limits; (10) the number and location of points for the Method 13 sampling runs would be determined according to the revised Method 1; (11) the use of a Type S pitot tube for making manifold intake nozzle adjustments would be disallowed; (12) the use of a differential pressure gauge conforming to the specifications of the revised Method 2 would be required for manifold intake nozzle velocity measurements; and (13) calibration of the thermocouple would be required after each test series, using the procedure outlined in the revised Method 2.

Due to the complexity of the amendments, the entire test method has been rewritten and is presented in revised form.

PUBLIC HEARING

A public hearing will be held to discuss the proposed standards in accordance with section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address above. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statements should be addressed to Mr. Jack R. Farmer at the address above.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section in Washington, D.C. (address same as above).

MISCELLANEOUS

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of this rulemaking. The principal purposes of the docket are (1) to allow members of the public and industries involved to identify and participate in the rulemaking process, and (2) to serve as the record for judicial review. The docket is required under section 307(d) of the Clean Air Act, as amended, and is available for public inspection and copying at the address above.

The proposed amendments would not alter the applicability date of Subpart S. Subpart S applies to all new primary aluminum plants for which construction or modification began after the original proposal date (October 23, 1974).

As prescribed by section 111 of the Clean Air Act, promulgation of the original standard of performance (41 FR 3826) was preceded by the Administrator's determination that primary aluminum plants contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare. In accordance with section 117 of the act, publication of the original proposed standard (39 FR 37739) was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues, and on the revised test method.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect:

> [T]he degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated (section 111(a)(1).)

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas, i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, section 173 of the act requires that a new or modified source constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such category of source. The statute defines LAER as that rate of emissions which reflects:

> (A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable or
>
> (B) The most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

In no event can the emission rate exceed any applicable new source performance standard (section 171(3).)

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the act (Part C). These provisions require that certain sources (referred to in section 169(1)) employ "best available control technology" (as defined in section 169(3)) for all pollutants regulated under the act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the act.

In all events, State implementation plans (SIP's) approved or promulgated under section 110 of the act must provide for the attainment and maintenance of National Ambient Air Quality Standards designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under section 116 of the act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. According-

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ly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

The major costs incurred by the proposed amendments are associated with the periodic emission testing requirement. EPA believes that these costs are reasonable and would have a negligible impact on: (1) Potential inflationary or recessionary effects; (2) competition with respect to small business; (3) consumer costs; and (4) energy use. The Administrator has determined that the proposed amendments are not "substantial" and do not require preparation of an Economic Impact Assessment.

Dated: September 8, 1978.

DOUGLAS M. COSTLE,
Administrator.

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

Subpart A—General Provisions

1. Section 60.8 is amended by revising paragraph (d) to read as follows:

§ 60.8 Performance tests.

* * * * *

(d) The owner or operator of an affected facility shall provide the Administrator 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have observers present.

* * * * *

Subpart S—Standards of Performance for Primary Aluminum Plants

2. Section 60.191 is amended by deleting paragraph (i) and by revising paragraphs (d) and (f) as follows:

§ 60.191 Definitions.

* * * * *

(d) "Potroom group" means an uncontrolled potroom, a potroom which is controlled individually, or a group of potrooms or potroom segments ducted to a common control system.

* * * * *

(f) "Aluminum equivalent" means an amount of aluminum which can be produced from a Mg of anodes produced by an anode bake plant as determined by § 60.195(g).

* * * * *

3. Section 60.192 is amended by revising paragraph (a) and adding paragraph (b) to read as follows:

§ 60.192 Standards for fluorides.

(a) On and after the date on which the initial performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases containing total fluorides, as measured according to § 60.8, above:

(1) 1.0 kg/Mg (2.0 lb/ton) of aluminum produced for potroom groups at Soderberg plants; except that emissions between 1.0 kg/Mg and 1.25 kg/Mg (2.5 lb/ton) will be considered in compliance if the owner or operator demonstrates that exemplary operation and maintenance procedures were used with respect to the emission control system and that proper control equipment was operating at the affected facility during the performance test;

(2) 0.95 kg/Mg (1.9 lb/ton) of aluminum produced for potroom groups at prebake plants; except that emissions between 0.95 kg/Mg and 1.25 kg/Mg (2.5 lb/ton) will be considered in compliance if the owner or operator demonstrates that exemplary operation and maintenance procedures were used with respect to the emission control system and that proper control equipment was operating at the affected facility during the performance test; and

(3) 0.05 kg/Mg (0.1 lb/ton) of aluminum equivalent for anode bake plants.

(b) Within 15 days of receipt of the results of a performance test which fall between the 1.0 kg/Mg and 1.25 kg/Mg levels in paragraph (a)(1) of this section or between the 0.95 kg/Mg and 1.25 kg/Mg levels in paragraph (a)(2) of this section, the owner or operator shall submit a report indicating whether all necessary control devices were on-line and operating properly during the performance test, describing the operation and maintenance procedures followed, and setting forth any explanation for the excess emissions, to the Director of the Enforcement Division of the appropriate EPA Regional Office.

4. Section 60.195 is amended as follows:

(a) By redesignating paragraphs (a) through (g) as (c) through (i) respectively;

(b) By deleting in redesignated paragraphs (g)(1), (h), and (i) the words "metric ton" wherever they appear and inserting in their place "Mg;"

(c) By deleting "(a)" in redesignated paragraph (e) and inserting in its place "(c);"

(d) By deleting the word "tons" in redesignated paragraph (g)(3) and inserting in its place "Mg;"

(e) By deleting "§ 60.195(d)" in redesignated paragraph (h) and inserting in its place "§ 60.195(f);"

(f) Be deleting "§ 60.195(e)" in redesignated paragraph (i) and inserting in its place "§ 60.195(g);"

(g) By adding new paragraphs (a) and (b), and by revising redesignated paragraph (f) as follows:

§ 60.195 Test methods and procedures.

(a) Following the initial performance test as required under §60.8(a), an owner or operator shall conduct a performance test at least once each month during the life of the affected facility, except when malfunction prevent representative sampling, as provided under § 60.8(c). The owner or operator shall give the Administrator at least 7 days advance notice of each test. The Administrator may require additional testing under section 114 of the Clean Air Act.

(b) An owner or operator may petition the Administrator to establish an alternative testing requirement that requires testing less frequently than once each month for a primary control system or an anode bake plant. If the owner or operator shows that emissions from the primary control system or the anode bake plant have low variability during day-to-day operations, the Administrator may establish such an alternative testing requirement. The alternative testing requirement shall include a testing schedule and, in the case of a primary control system, the method to be used to determine primary control system emissions for the purpose of performance tests. The Administrator shall publish the alternative testing requirement in the FEDERAL REGISTER.

* * * * *

(f) The rate of aluminum production is determined by dividing 720 hours into the weight of aluminum tapped from the affected facility during a period of 30 days prior to and including the final run of a performance test.

* * * * *

(Sec. 111, 114, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601(a)).)

APPENDIX A—REFERENCE METHODS

5. Method 14 is revised to read as follows:

14—DETERMINATION OF FLUORIDE EMISSIONS FROM POTROOM ROOF MONITORS OF PRIMARY ALUMINUM PLANTS

1. *Principle and applicability.*

1.1 *Principle*—Gaseous and particulate fluoride roof monitor emissions are drawn into a permanent sampling manifold through several large nozzles. The sample is transported from the sampling manifold to ground level through a duct. The gas in the duct is sampled using Method 13A or 13B—Determination of Total Fluoride Emissions from Stationary Sources. Effluent velocity and volumetric flow rate are determined with anemometers permanently located in the roof monitor.

1.2 *Applicability*—This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards.

2. *Apparatus.*

2.1 *Velocity measurement apparatus.*

2.1.1 *Anemometers*—Propeller anemometers, or equivalent. Each anemometer shall meet the following specifications: (1) Its propeller shall be made of polystyrene, or similar material of uniform density. To insure uniformity of performance among propellers, it is desirable that all propellers be made from the same mold; (2) the propeller shall be properly balanced, to optimize performance; (3) when the anemometer is mounted horizontally, its threshold velocity shall not exceed 15 m/min (50 fpm); (4) the measurement range of the anemometer shall extend to at least 600 m/min (2,000 fpm); (5) the anemometer shall be able to withstand prolonged exposure to dusty and corrosive environments; one way of achieving this is to continuously purge the bearings of the anemometer with filtered air during operation; (6) all anemometer components shall be properly shielded or encased, such that the performance of the anemometer is uninfluenced by potroom magnetic field effects; (7) a known relationship shall exist between the electrical output signal from the anemometer generator and the propeller shaft rpm, at minimum of three rpm settings between 60 and 1800 rpm; note that one of the three rpm settings shall be within 25 percent of 60 rpm. Anemometers having other types of output signals (e.g., optical) may be used, subject to the appoval of the Administrator. If other types of anemometers are used, there must still be a known relationship (as described above) between output signal and shaft rpm; also, each anemometer must be equipped with a suitable readout system.

2.1.2 *Installation of anemometers*—2.1.2.1 If the affected facility consists of a single, isolated potroom (or potroom segment), install at least one anemometer for every 85 meters of roof monitor length. If the length of the roof monitor divided by 85 meters is not a whole number, round the fraction to the nearest whole number to determine the number of anemometers needed. For monitors that are less than 130 m in length, use at least two anemometers. Divide the monitor cross-section into as many equal areas as anemometers and locate an anemometer at the centroid of each equal area.

2.1.2.2 If the affected facility consists of two or more potrooms (or potroom segments) ducted to a common control device, install anemometers in each potroom (or segment) that contains a sampling manifold. Install at least one anemometer for every 85 meters of roof monitor length of the potroom (or segment). If the potroom (or segment) length divided by 85 is not a whole number, round the fraction to the nearest whole number to determine the number of anemometers needed. If the potroom (or segment) length is less than 130 m, use at least two anemometers. Divide the potroom (or segment) monitor cross-section into as many equal areas as anemometers and locate an anemometer at the centroid of each equal area.

2.1.2.3 At least one anemometer shall be installed in the immediate vicinity (i.e., within 10 m) of the center of the manifold (see § 2.2.1). Make a velocity traverse of the width of the roof monitor where an anemometer is to be placed. This traverse may be made with any suitable low velocity measuring device, and shall be made during normal process operating conditions. Install the anemometer at a point of average velocity along this traverse.

2.1.3 *Recorders*—Recorders, equipped with suitable auxiliary equipment (e.g. transducers) for converting the output signal from each anemometer to a continuous recording of air flow velocity, or to an integrated measure of volumetric flowrate. For the purpose of recording velocity, "continuous" shall mean one readout per 15-minute or shorter time interval. A constant amount of time shall elapse between readings. Volumetric flow rate may be determined by an electrical count of anemometer revolutions. The recorders or counters shall permit identification of the velocities or flowrate measured by each individual anemometer.

2.1.4 *Pitot tube*—Standard-type pitot tube, as described in § 2.7 of Method 2, and having a coefficient of 0.99 ± 0.01.

2.1.5 *Pitot tube (optional)*—Isolated, Type S pitot tube, as described in § 2.1 of Method 2. The pitot tube shall have a known coefficient, determined as outlined in § 4.1 of Method 2.

2.1.6 *Differential pressure gauge.*—Inclined manometer or equivalent, as described in § 2.2 of Method 2.

2.2 *Roof monitor air sampling system.*

2.2.1 *Sampling ductwork*—A minimum of one manifold system shall be installed for each 'potroom group' (as defined in Subpart S, § 60.191). The manifold system and connecting duct shall be permanently installed to draw an air sample from the roof monitor to ground level. A typical installation of duct for drawing a sample from a roof monitor to ground level is shown in figure 14-1. A plan of a manifold system that is located in a roof monitor is shown in figure 14-2. These drawings represent a typical installation for a generalized roof monitor. The dimensions on these figures may be altered slightly to make the manifold system fit into a particular roof monitor, but the general configuration shall be followed. There shall be eight nozzles, each having a diameter of 0.40 to 0.50 meters. Unless otherwise specified by the Administrator, the length of the manifold system from the first nozzle to the eighth shall be 35 meters or eight percent of the length of the potroom (or potroom segment) roof monitor, whichever is greater. The duct leading from the roof monitor manifold shall be round with a diameter of 0.30 to 0.40 meters. As shown in figure 14-2, each of the sample legs of the manifold shall have a device, such as a blast gate or valve, to enable adjustment of flow into each sample nozzle.

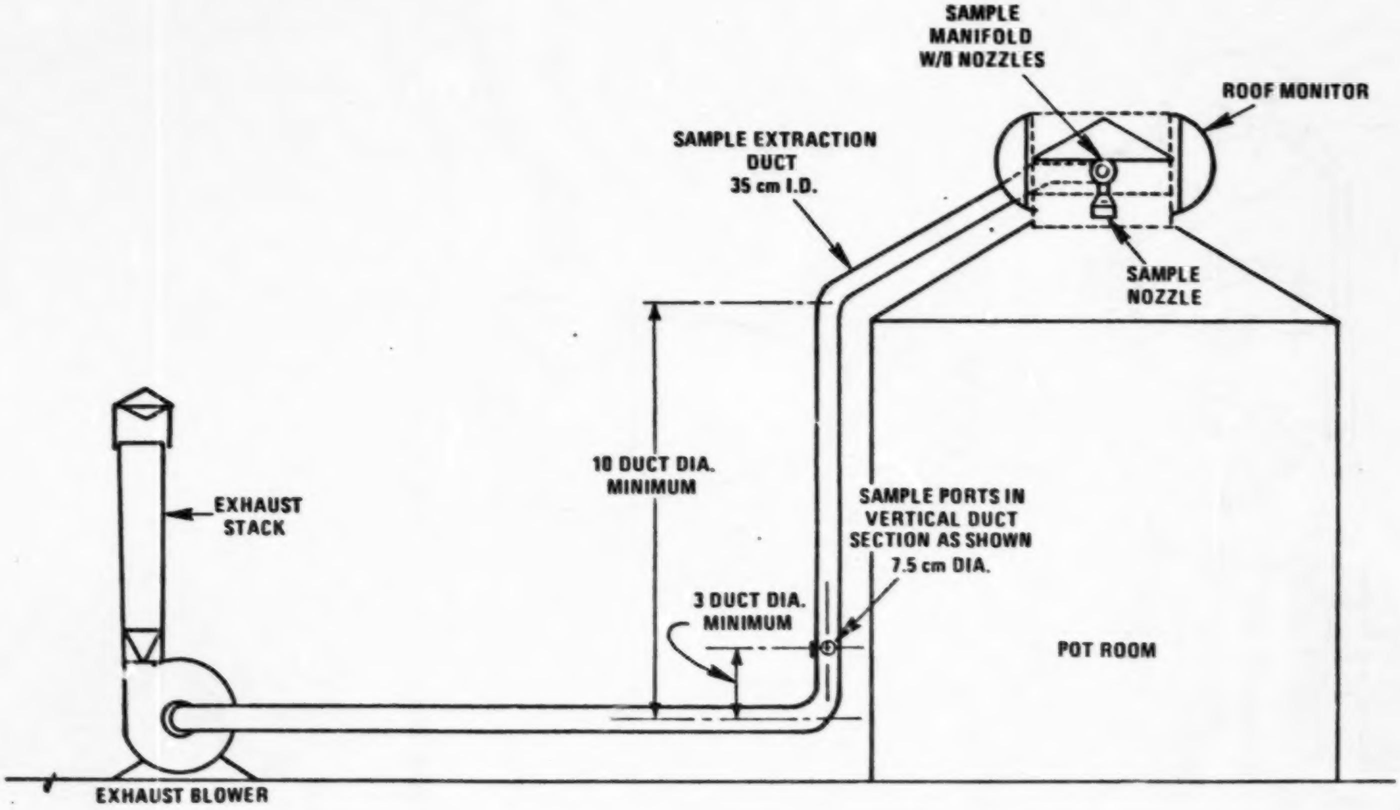
SAMPLE MANIFOLD W/8 NOZZLES
ROOF MONITOR
SAMPLE EXTRACTION DUCT 35 cm I.D.
SAMPLE NOZZLE
10 DUCT DIA. MINIMUM
EXHAUST STACK
SAMPLE PORTS IN VERTICAL DUCT SECTION AS SHOWN 7.5 cm DIA.
3 DUCT DIA. MINIMUM
POT ROOM
EXHAUST BLOWER

Figure 14-1. Roof monitor sampling system.

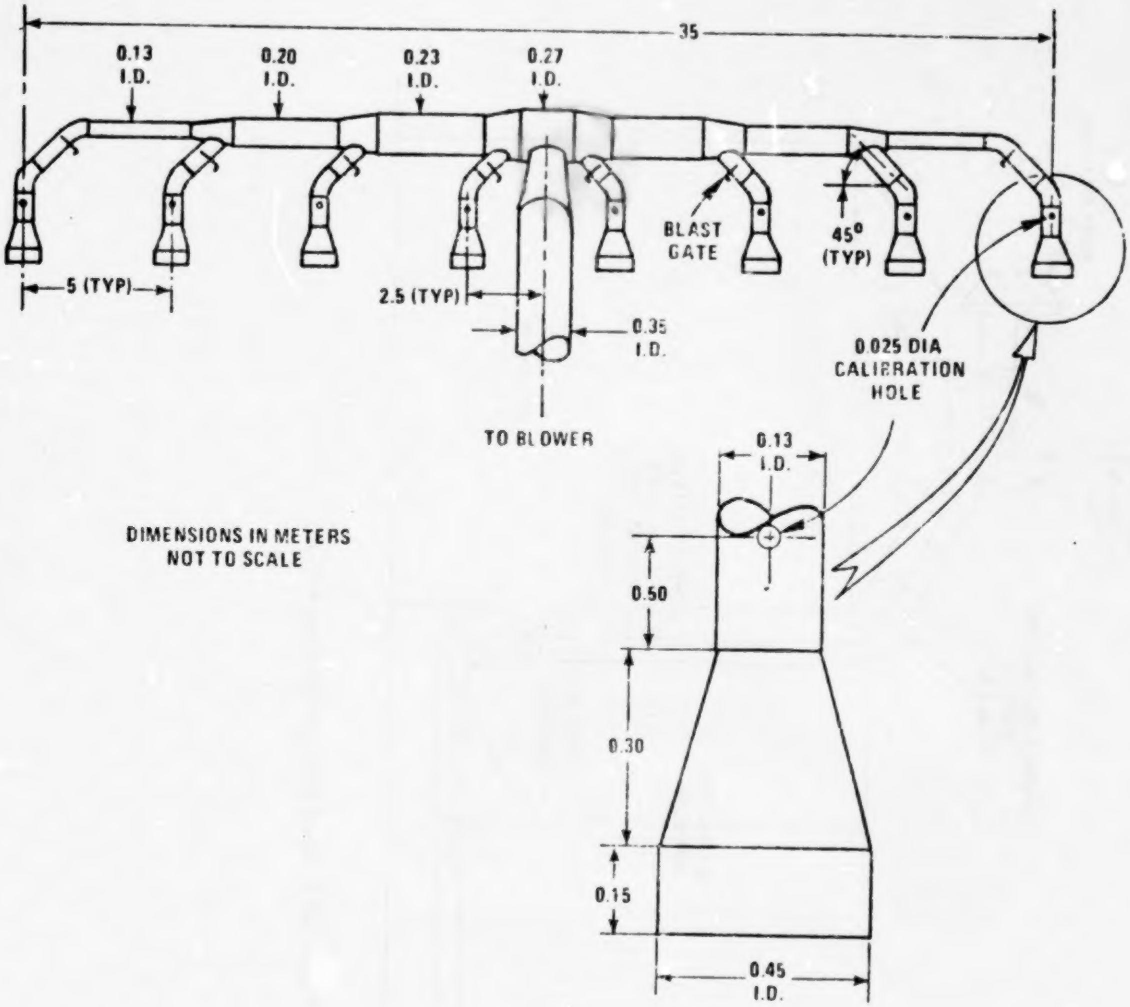
35
0.13
I.D.
0.20
I.D.
0.23
I.D.
0.27
I.D.
BLAST
GATE
45°
(TYP)
5 (TYP)
2.5 (TYP)
0.35
I.D.
TO BLOWER
0.025 DIA
CALIBRATION
HOLE
DIMENSIONS IN METERS
NOT TO SCALE
0.13
I.D.
0.50
0.30
0.15
0.45
I.D.

Figure 14-2. Sampling manifold and nozzles.

The manifold shall be located in the immediate vicinity of one of the propeller anemometers (see § 2.1.2.3) and as close as possible to the midsection of the potroom (or potroom segment). Avoid locating the manifold near the end of a potroom or in a section where the aluminum reduction pot arrangement is not typical of the rest of the potroom (or potroom segment). Center the sample nozzles in the throat of the roof monitor (see fig. 14-1). Construct all sample-exposed surfaces within the nozzles, manifold and sample duct of 316 stainless steel. Aluminum may be used if a new ductwork system is conditioned with fluoride-laden roof monitor air for a period of six weeks prior to initial testing. Other materials of construction may be used if it is demonstrated through comparative testing that there is no loss of fluorides in the system. All connections in the ductwork shall be leak free.

Locate two sample ports in a vertical section of the duct between the roof monitor and exhaust fan. The sample ports shall be at least 10 duct diameters downstream and three diameters upstream from any flow disturbance such as a bend or contraction. The two sample ports shall be situated 90° apart. One of the sample ports shall be situated so that the duct can be traversed in the plane of the nearest upstream duct bend.

2.2.2 *Exhaust fan*—An industrial fan or blower shall be attached to the sample duct at ground level (see fig. 14-1). This exhaust fan shall have a capacity such that a large enough volume of air can be pulled through the ductwork to maintain an isokinetic sampling rate in all the sample nozzles for all flow rates normally encountered in the roof monitor.

The exhaust fan volumetric flow rate shall be adjustable so that the roof monitor air can be drawn isokinetically into the sample nozzles. This control of flow may be achieved by a damper on the inlet to the exhauster or by any other workable method.

2.3 *Temperature measurement apparatus.* 2.3.1 *Thermocouple*—Install a thermocouple in the roof monitor near the sample duct. The thermocouple shall conform to the specifications outlined in § 2.3 of Method 2.

2.3.2 *Signal Transducer*—Transducer, to change the thermocouple voltage output to a temperature readout.

2.3.3 *Thermocouple Wire*—To reach from roof monitor to signal transducer and recorder.

2.3.4 *Recorder*—Suitable recorder to monitor the output from the thermocouple signal transducer.

2.4 *Sampling train*—Use the train described in Methods 13A and 13B.

3. *Reagents.*

3.1 *Sampling and analysis.* Use reagents described in Method 13A or 13B.

4. *Calibration.*

4.1 *Propeller anemometers.* 4.1.1 *Initial calibration*—Anemometers which meet the specifications outlined in § 2.1.1 need not be calibrated, provided that a reliable performance curve relating anemometer signal output to air velocity (covering the velocity range of interest) is available from the manufacturer. For the purposes of this method, a "reliable" performance curve is defined as one that has been derived from primary standard calibration data, with the anemometer mounted vertically. "Primary standard" data are obtainable by: (1) Direct calibration of one or more of the anemometers by the National Bureau of Standards (NBS); (2) NBS-traceable calibration; or (3) Calibration by direct measurement of fundamental parameters such as length and time (e.g., by moving the anemometers through still air at measured rates of speed, and recording the output signals). If a reliable performance curve is not available from the manufacturer, such a curve shall be generated, using one of the three methods described immediately above.

4.1.2 *Recalibration*—Extended field use of propeller anemometers can cause deterioration of some of the anemometer components, thus affecting performance. Therefore, a performance-check of each anemometer shall be made before (optional) and after (mandatory) each test series. The performance-check shall be done as outlined in § 4.1.2.1 through 4.1.2.3, below. Alternatively, the tester may use any other suitable method, subject to the approval of the Administrator, that takes into account the signal output, propeller condition and threshold velocity of the anemometer.

4.1.2.1 Check the signal output of the anemometer by using an accurate rpm generator (see fig. 14-3) or synchronous motors to spin the propeller shaft at each of the three rpm settings described in § 2.1.1 above (specification No. 7), and measuring the output signal at each setting. If, at each setting, the output signal is within ±5 percent of its original value, the anemometer can continue to be used. If the anemometer performance is unsatisfactory, the anemometer shall either be replaced or repaired.

4.1.2.2 Check the propeller condition, by visually inspecting the propeller, making note of any significant damage or warpage; damaged or deformed propellers shall be replaced.

4.1.2.3 Check the anemometer threshold velocity as follows: With the anemometer mounted as shown in figure 14-4(A), fasten a known weight (a straight pin will suffice) to the anemometer propeller, at a fixed distance from the center of the propeller shaft. This will generate a known torque; for example, a 0.1 g weight, placed 10 cm from the center of the shaft, will generate a torque of 1.0 g-cm. If the known torque causes the propeller to rotate downward, approximately 90° (see fig. 14-4(B)), then the known torque is greater than or equal to the starting torque; if the propeller fails to rotate approximately 90°, the known torque is less than the starting torque. By trying different combinations of weight and distance, the starting torque of a particular anemometer can be satisfactorily estimated. Once an estimate of the starting torque has been obtained, the threshold velocity of the anemometer (for horizontal mounting) can be estimated from a graph such as figure 14-5. If the horizontal threshold velocity is acceptable [<16.7m/min (55 fpm), when this technique is used], the anemometer can continue to be used. If the threshold velocity of an anemometer is found to be unacceptably high, the anemometer shall either be replaced or repaired.

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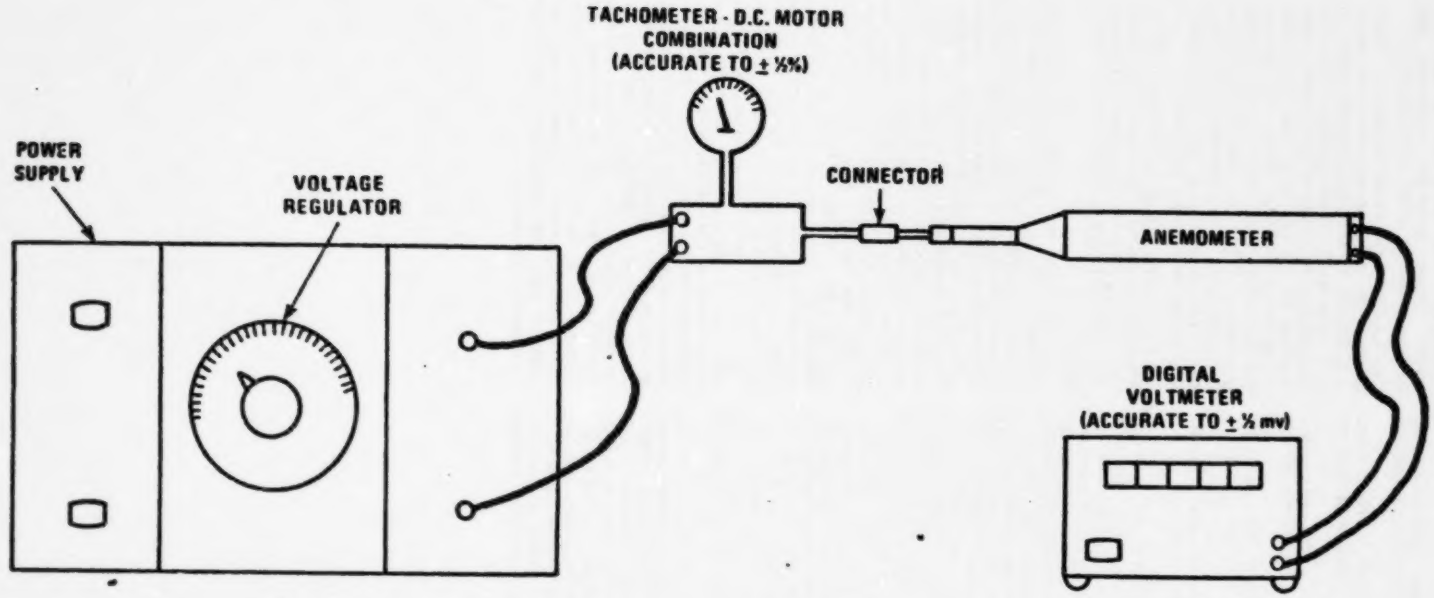
TACHOMETER - D.C. MOTOR
COMBINATION
(ACCURATE TO ± ½%)
POWER SUPPLY
VOLTAGE REGULATOR
CONNECTOR
ANEMOMETER
DIGITAL
VOLTMETER
(ACCURATE TO ± ½ mv)

Figure 14-3. Typical RPM generator.

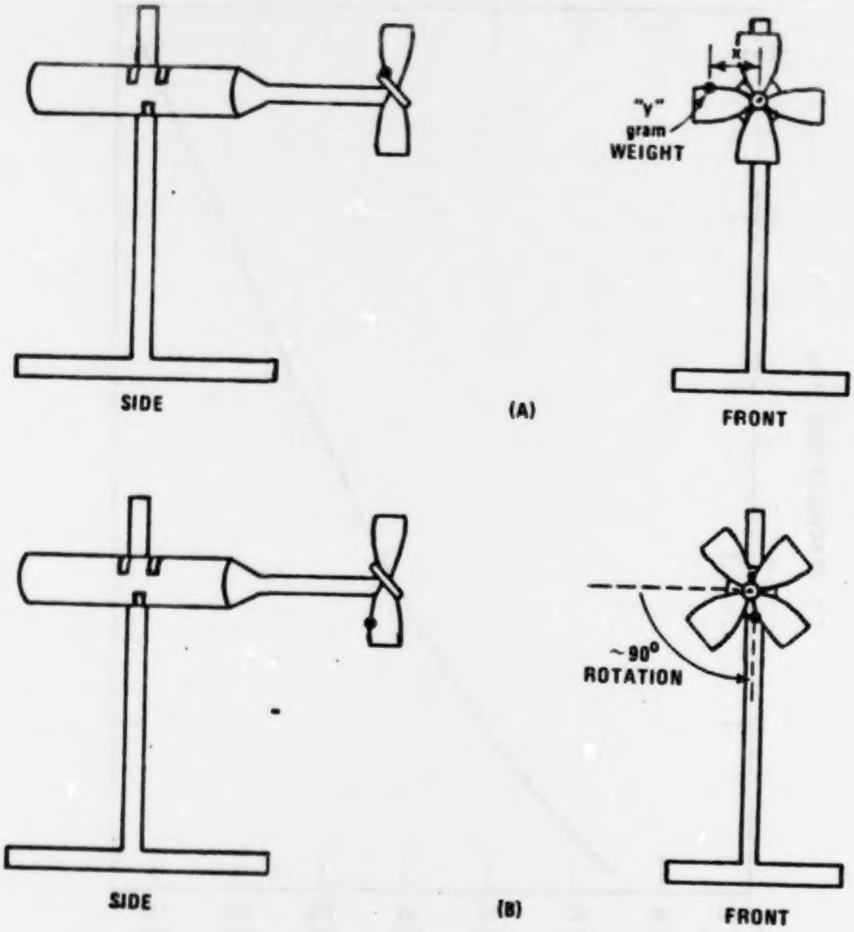
"y"
gram
WEIGHT
x
SIDE
(A)
FRONT
~90°
ROTATION
SIDE
(B)
FRONT

Figure 14-4. Check of anemometer starting torque. A "y" gram weight placed "x" centimeters from center of propeller shaft produces a torque of "xy" g-cm. The minimum torque which produces a 90° (approximately) rotation of the propeller is the "starting torque."

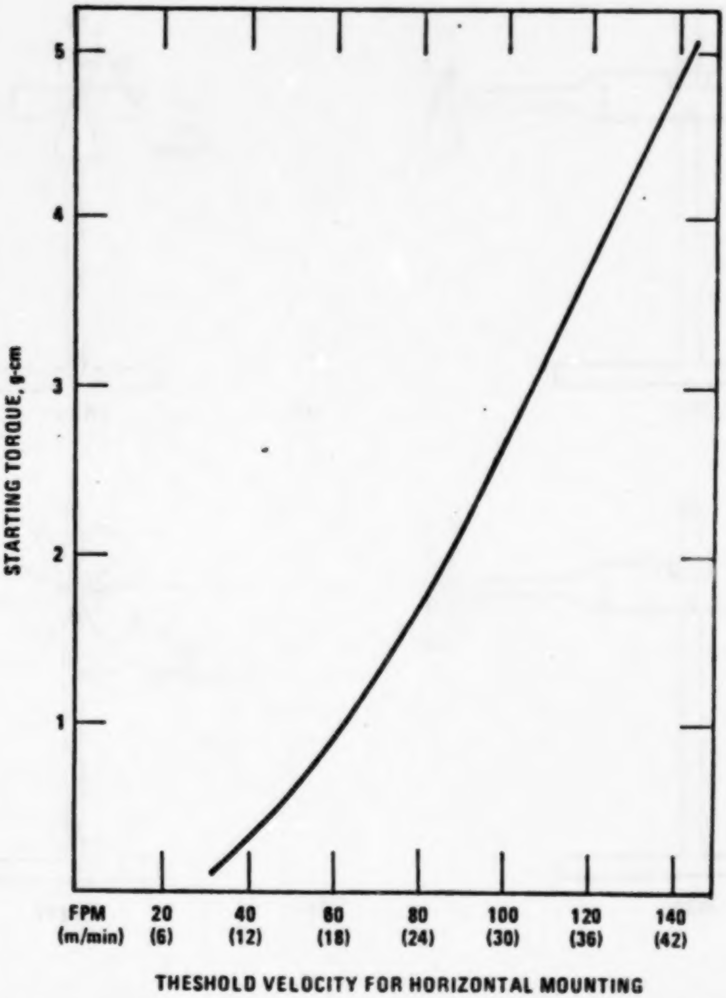

Figure 14-5. Typical curve of starting torque vs horizontal threshold velocity for propeller anemometers. Based on data obtained by R.M. Young Company, May, 1977.

4.1.2.4 If an anemometer fails the post-test performance-check (i.e., if repair or replacement of any anemometer components is necessary), proceed as follows: (1) Calibrate the anemometer (before repairing it), using one of the three methods described in section 4.1.1, above. Alternatively, the anemometer may be calibrated against another propeller anemometer that meets the specifications of section 2.1.1 (a detailed procedure is described in Citation 1 of section 7); (2) referring to the calibration curve obtained in step (1), recalculate (for each run) the average velocity (v) for the anemometer, using the data print-out obtained during the test series; (3) Compare each recalculated value of v against the reported value. If the recalculated value of v is less than the reported value, no adjustment in the reported overall average velocity for the run shall be made. If, however, the recalculated value of v exceeds the reported value, replace the reported value of v with the recalculated value, and then recompute the overall average velocity (and total flowrate).

NOTE.—If the anemometer located in the section of the roof monitor containing the sampling manifold fails the performance check, additional emission rate adjustments may be necessary (see section 6.1).

4.2 *Manifold Intake Nozzles.*—Adjust the exhaust fan to draw a volumetric flow rate (refer to equation 14-1) such that the entrance velocity into each manifold nozzle approximates the average effluent velocity in the roof monitor. Measure the velocity of the air entering each nozzle by inserting a standard pitot tube into a 2.5 cm or less diameter hole (see fig. 14-2) located in the manifold between each blast gate (or valve) and nozzle. Note that a standard pitot tube is used, rather than a type S, to eliminate possible velocity measurement errors due to cross-section blockage in the small (0.13 m diameter) manifold leg ducts. The pitot tube tip shall be positioned at the center of each manifold leg duct. Take care to insure that there is no leakage around the pitot tube, which could affect the indicated velocity in the manoifold leg. If the velocity of air being drawn into each nozzle is not the same, open or close each blast gate (or valve) until the velocity in each nozzle is the same. Fasten each blast gate (or valve) so that it will remain in this position and close the pitot port holes. This calibration shall be performed when the manifold system is installed.

NOTE.—It is recommended that this calibration be repeated at least once a year.

4.3 *Thermocouple.*—After each test series, the thermocouple shall be calibrated, using the procedures outlined in section 4.3 of method 2.

4.4 *Recorders and/or Counters.*—After each test series, check the calibration of each recorder and/or counter that was used (see section 2.1.3). Check the recorder or counter calibration at a minimum of three points, approximately spanning the range of velocities observed during the test series. use the calibration procedures recommended by the manufacturer, or other suitable procedures (subject to the approval of the Administrator). If a recorder or counter is found to be out of calibration, by an average amount greater than 5 percent for the three calibration points, proceed as follows: (1) Based on the results of the post-test calibration check, recalculate (for each run) the average velocity (v) for the anemometer that was connected to the recorder during the test series. If a particular recalculated value of v is less than the reported value, no adjustment in the reported overall average velocity for the run shall be made. If, however, the recalculated value of v is greater than the reported value, replace the reported value of v with the recalculated value, and recompute the overall average velocity (and total flowrate).

NOTE.—If the malfunctioning recorder or counter was connected to the anemometer in the section of the roof monitor containing the sampling manifold, additional emission rate adjustments may be necessary (see § 6.1).

5. *Procedure.*

5.1 *Roof Monitor Velocity Determination.* 5.1.1 *Velocity estimate(s) for setting isokinetic flow*—To assist in setting the flow in the manifold sample nozzles to isokinetic, the anticipated average velocity in the section of the roof monitor containing the sampling manifold shall be estimated prior to each test run. The tester may use any convenient means to make this estimate (e.g., the velocity indicated by the anemometer in the section of the roof monitor containing the sampling manifold may be continuously monitored during the 24-hour period prior to the test run.

If there is question as to whether a single estimate of average velocity is adequate for an entire test run (e.g., if velocities are anticipated to be significantly different during different potroom operations), the tester may opt to divide the test run into two or more "sub-runs," and to use a different estimated average velocity for each sub-run (see § 5.3.2.2).

5.1.2 *Velocity determination during a test run.*—During the actual test run, record the velocity or volumetric flowrate readings of each propeller anemometer in the roof monitor. readings shall be taken for each anmometer every 15 minutes or at shorter equal time intervals (or continuously).

5.2 *Temperature recording.* Record the temperature of the roof monitor every 2 hours during the test run.

5.3 *Sampling.* 5.3.1 *Preliminary air flow in duct.*—During the 24 hours preceding the test, turn on the exhaust fan and draw roof monitor air through the manifold duct to condition the ductwork. Adjust the fan to draw a volumetric flow through the duct such that the velocity of gas entering the manifold nozzles approximates the average velocity of the air exiting the roof monitor in the vicinity of the sampling manifold.

5.3.2 *Isokinetic sample rate adjustment(s)*—5.3.2.1 *Initial adjustment.*—Prior to the test run (or first sub-run, if applicable; see §§ 5.1.1 and 5.3.2.2), adjust the fan to provide the necessary volumetric flowrate in the sampling duct, so that air enters the manifold sample nozzles at a velocity equal to the appropriate estimated average velocity determined under § 5.1.1. Equation 14-1 gives the correct stream velocity needed in the duct at the sampling location, in order for sample gas to be drawn isokinetically into the manifold nozzles. Next, verify that the correct average stream velocity has been achieved, by performing a pitot tube traverse of the sample duct (using either a standard or type S pitot tube); use the procedure outlined in method 2.

$$V_d = \frac{6\,(D_n)^2}{(D_d)^2}\,(V_m)\,\frac{1\ \text{minute}}{60\ \text{sec}} \qquad \text{(Equation 14-1)}$$

Where:

V_d = Desired velocity in duct at sampling location, meters/sec.

D_n = Diameter of a roof monitor manifold nozzle, meters.

D_d = Diameter of duct at sampling location, meters.

V_m = Average velocity of the air stream in the roof monitor, meters/minute, as determined under § 5.1.1.

5.3.2.2 *Adjustments during run.*—If the test run is divided into two or more "sub-runs" (see § 5.1.1), additional isokinetic rate adjustment(s) may become necessary during the run. Any such adjustment shall be made just before the start of a sub-run, using the procedure outlined in § 5.3.2.1 above.

NOTE.—Isokinetic rate adjustments are not permissible during a sub-run.

5.3.3 *Sample train operation.*—Sample the duct using the standard fluoride train and methods described in methods 13A and 13B. Determine the number and location of the sampling points in accordance with method 1. A single train shall be used for the entire sampling run. Alternatively, if two or more sub-runs are performed, a separate train may be used for each sub-run; note, however, that is this option is chosen, the area of the sampling nozzle shall be the same (±2 percent) for each train. If the test run is divided into sub-runs, a complete traverse of the duct shall be performed during each sub-run.

5.3.4 *Time per run.*—Each test run shall last 8 hours or more; if more than one run is to be performed, all runs shall be of approximately the same (±10 percent) length. If question exists as to the representativeness of an 8-hour test, a longer period may be selected. Conduct each run during a period when all normal operations are performed underneath the sampling manifold. During the test period, all pots in the potroom group shall be operated such that emissions are representative of normal operating conditions in the potroom group.

5.3.5 *Sample recovery.*—Use the sample recovery procedures described in method 13A or 13B.

5.4 *Analysis.*—Use the analysis procedures described in method 13A or 13B.

6. *Calculations.*

6.1 *Isokinetic sampling check.* 6.1.1 Calculate the mean velocity (V_m) for the sampling run, as measured by the anemometer in the section of the roof monitor containing the sampling manifold. If two or more sub-runs have been performed, the tester may opt to calculate the mean velocity for each sub-run.

6.1.2 Using equation 14-1, calculate the expected average velocity (V_d) in the sampling duct, corresponding to each value of V_m obtained under § 6.1.1.

6.1.3 Calculate the actual average velocity (v_s) in the sampling duct for each run or sub-run, according to equation 2-9 of method 2, and using data obtained from method 13.

6.1.4 Express each value of v_s from § 6.1.3 as a percentage of the corresponding V_d value from § 6.1.2.

6.1.4.1 If v_s is less than or equal to 120 percent of V_d, the results are acceptable (note that in cases where the above calculations have been performed for each sub-run, the results are acceptable if the average percentage for all sub-runs is less than or equal to 120 percent)

6.1.4.2 If v_s is more than 120 percent of V_d, multiply the reported emission rate by the following factor:

$$1 + \frac{\frac{100\,v_s}{V_s} - 100}{200}$$

6.2 *Average velocity of roof monitor gases.* Calculate the average roof monitor velocity using all the velocity or volumetric flow readings from § 5.1.2.

6.3 *Roof monitor temperature.* Calculate the mean value of the temperatures recorded in § 5.2.

6.4 *Concentration of fluorides in roof monitor air (in mg F/m³).* 6.4.1 If a single sampling train was used throughout the run, calculate the average fluoride concentration for the roof monitor using equation 13A-5 of method 13A.

6.4.2 If two or more sampling trains were used (i.e., one per sub-run), calculate the average fluoride concentration for the run, as follows:

$$\bar{C}_s = \frac{\sum_{i=1}^{n} (F_t)_i}{\sum_{i=1}^{n} (V_{m(std)})_i} \qquad \text{(Equation 14-2)}$$

where:

C_s = Average fluoride concentration in roof monitor air, mg F/dscm.

$(F_t)_i$ = Total fluoride mass collected during a particular sub-run, mg F (from equation 13A-4 of method 13A or equation 13B-1 of method 13B).

$(V_{m(std)})_i$ = Total volume of sample gas passing through the dry gas meter during a particular sub-run, dscm (see equation 13A-1 of method 13A).

n = Total number of sub-runs.

6.5 Average volumetric flow from the roof monitor of the potroom(s) (or potroom segment(s)) containing the anemometers is given by equation 14-3.

$$Q_m = \frac{V_{mt}\,(A)\,(M_d)\,P_m\,(293°K)}{(T_m + 273°)\,(760\text{ mm Hg})} \qquad \text{(Equation 14-3)}$$

where:

Q_m = Average volumetric flow from roof monitor at standard conditions on a dry basis, m³/min.

A = Roof monitor open area, m².

V_{mt} = Average velocity of air in the roof monitor, meters/minute, from § 6.2.

P_m = Pressure in the roof monitor; equal to barometric pressure for this application, mm Hg.

T_m = Roof monitor temperature, °C, from § 6.3.

M_d = Mole fraction of dry gas, which is given by:

$$M_d = \frac{100 - 100(B_{ws})}{100}$$

NOTE.—B_{ws} is the proportion by volume of water vapor in the gas stream, from equation 13A-3, method 13A.

7. *Bibliography.* 1. A Simplified Procedure for Conducting Post-Test Calibration Checks of Propeller Anemometers. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. July 1978.

2. Shigehara, R. T. A Guideline for Evaluating Compliance Test Results (Isokinetic Sampling Rate Criterion). U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. August 1977.

[FR Doc. 78-26244 Filed 9-18-78; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

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STATIONARY GAS TURBINES

Standards of Performance for New Stationary Sources

SUBPART GG

V-GG-i

[6506–01]

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 777–8]

STATIONARY GAS TURBINES

Standards of Performance for New Stationary Sources

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The proposed standards would limit emissions of nitrogen oxides and sulfur dioxide from new, modified and reconstructed stationary gas turbines to 75 ppm and 150 ppm, respectively. A new reference method for determining the concentration of nitrogen oxides, sulfur dioxide and oxygen in the exhaust gases from stationary gas turbines is also proposed. The standards implement the Clean Air Act and are based on the Administrator's determination that stationary gas turbine emissions contribute significantly to air pollution. The intended effect is to require new, modified and reconstructed stationary gas turbines to use the best demonstrated system of emission reduction.

DATES: Comments must be received on or before December 2, 1977.

ADDRESSES: Comments should be submitted, preferably in triplicate, to the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, Attention: Mr. Don R. Goodwin.

The Standards Support and Environmental Impact Statement (SSEIS) containing the data and information upon which the proposed standards are based may be obtained from the Public Information Center (PM–215), U.S. Environmental Protection Agency, Washington, D.C. 20460 (specify "Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Stationary Gas Turbines").

The SSEIS and all public comments received may be inspected and copied at the Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone No. 919–541–5271.

SUPPLEMENTARY INFORMATION:

PROPOSED STANDARDS

The proposed standards would apply to all new, modified and reconstructed stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (about 1,000 horsepower). The standards would apply to simple and regenerative cycle gas turbines and to the gas turbine portion of a combined cycle steam/electric generating system.

The proposed standards would limit the concentration of nitrogen oxides (NO_x) in the exhaust gases from stationary gas turbines to 0.0075 percent by volume (75 ppm) at 15 percent oxygen on a dry basis. This emission limit would be adjusted upward for turbines with thermal efficiencies greater than 25 percent and upward for turbines burning fuels with a nitrogen content greater than 0.015 percent by weight.

The proposed standard would be referenced to International Standard Organization (ISO) standard day conditions of 288 degrees Kelvin, 60 percent relative humidity, and 101.3 kilopascals (1 atmosphere) pressure. Measured NO_x emission levels, therefore, would be adjusted to ISO reference conditions by use of an ambient condition correction factor included in the standard or by a custom ambient condition correction factor developed by the gas turbine manufacturer, owner, or operator and approved for use by EPA. Manufacturers, owners, or operators electing to develop custom ambient condition correction factors, however, would be required to develop such factors in terms of the following variables: combustor inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. All correction factors would have to be substantiated with data and approved for use by the Administrator before they could be used for determining compliance with the proposed standard.

Stationary gas turbines with a heat input at peak load from 10.7 to, and including, 107.2 gigajoules per hour would be exempt from the NO_x emission limit for five years from the date of this proposal. Emergency-standby gas turbines, military gas turbines and firefighting gas turbines would be exempt permanently from the NO_x emission limit. In addition, stationary gas turbines using wet controls would be exempt temporarily from the NO_x emission limit during those periods when ice fog created by the gas turbine was deemed by the owner or operator of the gas turbine to present a traffic hazard. None of the exemptions mentioned in this paragraph would apply to the SO_2 emission limit.

The proposed standards would limit the SO_2 concentration in the exhaust gases from stationary gas turbines to 0.015 percent by volume (150 ppm) corrected to 15 percent oxygen on a dry basis, or would limit the sulfur content of the fuel used by any stationary gas turbine to 0.8 percent by weight.

SUMMARY OF ENVIRONMENTAL AND ECONOMIC IMPACTS

The proposed standards would reduce NO_x emissions from stationary gas turbines by about 70 percent. Based on industry growth projections, by 1982 a reduction in national NO_x emissions of about 190,000 tons per year would be realized. By 1987, the reduction in national NO_x emissions would reach about 400,000 tons per year.

The adverse water pollution impact of the proposed standards would be minimal. The quantity of water or steam required for injection into the gas turbins to reduce NO_x emission would be small, less than 5 percent of the water consumed by a comparable size steam/electric power plant using cooling towers.

The solid waste impact of the proposed standards would be negligible. There would also be no adverse noise impact resulting from the proposed standards.

The energy impact of the proposed standards would be small. Gas turbine fuel consumption would be increased from 0 to 5 percent, depending largely on the rate of water injection required to comply with the proposed NO_x standard. There would be no energy impact associated with the proposed SO_2 standard. Few turbines will require the high water injection rates (about 1:1 water-to-fuel ratios) which result in a 5 percent fuel penalty. Assuming that all stationary gas turbines subject to the proposed NO_x standard would require a 1:1 water-to-fuel ratio, the fifth year (1982) energy impact of the standard on large stationary gas turbines would be an increase in fuel consumption of about 5,500 barrels of fuel oil per day. The fifth-year (1987) energy impact of the NO_x standard on small stationary gas turbines would be an increase in fuel consumption of about 7,000 barrels of fuel oil per day. This is equivalent to an increase in projected 1982 and 1987 national crude oil consumption of less than 0.03 percent. These estimates are based on assumptions which yield the greatest energy impacts and actual impacts are expected to be much lower.

The economic impact of the proposed standards is considered to be reasonable. The proposed standards would increase the capital costs or purchase price of a gas turbine for most installations by about 1 to 4 percent. For offshore applications, however, such as oil and gas drilling platforms, the increase could be as much as 7 percent. The annualized costs for a gas turbine in all applications would be increased by about 1 to 4 percent, with the largest application, utilities, realizing less than a 2 percent increase.

The proposed standards would increase the total capital investment requirements for all users of large stationary gas turbines by about 36 million dollars by 1982. For the period 1982 through 1987, the standards would increase the capital investment requirements for all users of both large and small stationary gas turbines by about 67 million dollars. Total annualized costs would be increased by about 11 million dollars in 1982 and by about 30 million dollars in 1987. These impacts would result in price increases for the end products or services provided by industrial and commercial users of stationary gas turbines ranging from less than 0.01 percent in the petroleum refining industry to about 0.1 percent in the electric utility industry.

The criteria for an action to be considered major, thereby requiring development of an Economic Impact Analysis (EIA) are: (1) an increase in the fifth-year annualized costs of 100 million dollars, (2) a major product price increase of 5 percent, or (3) an increase in national energy consumption of 25,000 barrels of fuel oil per day. The impacts resulting from the proposed standards would not exceed these criteria, except possibly for offshore applications, where the proposed standards could increase the price of a gas turbine by about 7 percent. Most gas turbines used on offshore oil and gas drilling platforms, however, are likely to have a heat input at peak capacity of less than 107.2 gigajoules per hour (about 10,000 horsepower). Consequently, they would be considered small gas turbines and would be exempt from the standards for five years. In any event, stationary gas turbines sold for offshore applications constitute such a small percentage (estimated at less than 3 percent) of the overall market for gas turbines that they are not considered a major product within the intent of the 5 percent major product price increase criteria for preparation of an EIA. Consequently, the proposed standards would not constitute a major action and no EIA has been prepared.

RATIONALE

SELECTION OF SOURCE FOR CONTROL

Assuming existing levels of emission controls, national NO_x emissions from stationary sources are projected to increase by about 65 percent by 1985. Applying best technology to all new sources would reduce this increase to about 25 percent, but would not prevent it from occurring. This unavoidable increase in NO_x emissions is attributable largely to the fact that few of the NO_x emission control techniques currently available can achieve large reductions in NO_x emissions. Consequently, EPA has assigned a high priority to the development of standards of performance for major NO_x emission sources wherever significant reductions in NO_x emissions can be achieved.

Several studies sponsored by EPA have ranked stationary gas turbines as major controllable sources of NO_x emissions. One study conducted by the Aerotherm Division of Acurex Corporation estimated that oil-fired and gas-fired stationary gas turbines accounted for 2.5 percent of the total NO_x emissions from stationary sources in the U.S. in 1972. This same study ranked gas-fired turbines as sixteenth and oil-fired gas turbines as twenty-third in a priority listing of 137 controllable stationary sources of NO_x emissions.

In another study the Research Corp. of New England (TRC) determined the impact which standards of performance would have on nationwide emissions of particulates, NO_x, SO_2, HC (hydrocarbons), and CO (carbon monoxide) from stationary sources. Sources were then ranked according to the impact a standard promulgated in 1975 would have on emissions in 1985. This ranking placed gas turbines first on a list of 40 stationary NO_x emission sources and eighth on a list of 41 stationary SO_2 emission sources.

In 1974, 90 percent of all domestic stationary gas turbine capacity was sold to the electric utility market, primarily for use as peaking units. It is expected that this large percentage of sales to utilities will continue in the future due to the many advantages of gas turbines as peaking units. In addition, gas turbine peaking units are often located in large urban centers where power demands are greatest and pollution problems are often most severe.

Stationary gas turbines, therefore, are significant contributors to total nationwide emissions of NO_x. They are ranked high on the various listings of sources for which standards of performance should be developed. In addition, the turbines coupled with the probability that many gas turbines will be installed near large urban centers underscores the need for standards of performance for stationary gas turbines. Consequently, stationary gas turbines were selected for development of standards of performance.

SELECTION OF POLLUTANTS

The pollutants emitted from stationary gas turbines are particulates, NO_x; SO_2, CO and HC. Combustor modifications (dry control) and water injection (wet control) are demonstrated techniques for reducing NO_x emissions at reasonable cost and depending on specific emission level selected, could reduce NO_x emissions by up to 190,000 tons per year in 1982. This is a significant decrease in total nationwide NO_x emissions. For these reasons, NO_x emissions from stationary gas turbines were selected for control by standards of performance.

SO_2 emissions from stationary gas turbines depend on the sulfur content of the fuel since nearly 100 percent of the fuel sulfur is converted to SO_2 during the combustion process. Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emissions from stationary gas turbines is considered unreasonable. Control of SO_2 emissions, therefore, would require combustion of low sulfur fuels rather than the application of FGD. Selection of low sulfur fuels, however, is considered reasonable. Since gas turbines are a major source of SO_2 emissions and firing low sulfur fuels is considered an economically feasible control technique, SO_2 emissions from stationary gas turbines were selected for control by standards of performance.

HC and CO emissions from stationary gas turbines operating at peak load are relatively low because the higher the percentage of peak load at which a turbine operates, the more efficient the combustion of the fuel. Gas turbines normally operate at 80 to 100 percent of peak load with HC emissions averaging less than 50 ppm and CO emissions averaging less than 500 ppm at 15 percent oxygen. HC and CO emissions from stationary gas turbines, therefore, were not selected for control by standards of performance.

Particulate emissions from stationary gas turbines depend on the ash content of the fuel and are minimal. Consequently, particulate emissions from stationary gas turbines were not selected for control by standards of performance.

SELECTION OF AFFECTED FACILITIES

Stationary gas turbines can be used in three different configurations: simple cycle, regenerative cycle, and combined cycle. All of these configurations emit NO_x and SO_2, and all can be controlled for NO_x emissions by water injection or dry controls and for SO_2 by the firing of low sulfur fuels. Consequently, simple cycle gas turbines, regenerative cycle gas turbines and the gas turbine portion of combined cycle steam/electric generating systems were selected as the affected facilities for standards of performance limiting NO_x and SO_2 emissions.

Gas turbines can burn either liquid or gaseous fuels. Dry and wet control techniques for the control of NO_x can be applied to gas turbines regardless of the type of fuel burned. Similarly, the firing of low sulfur fuel for the control of SO_2 emissions can be applied to gas turbines regardless of the type of fuel burned. EPA recognizes the fact that at the present time gas turbines firing coal-derived fuels probably could not meet the standards of performance. Coal-derived fuels, however, will not be available in commercial quantities to gas turbines for at least ten years and EPA feels that by that time the emission control technology for clean firing of these fuels could be developed. Consequently, gas turbines burning all types of fuels are selected as affected facilities for standards of performance.

For many applications up to about 10,000 hp stationary gas turbines compete with internal combustion engines. A standard of performance on one of these industries and not the other would tend to give the non-regulated industry a competitive advantage to some extent.

Currently, standards of performance are being developed for stationary internal combustion engines. Although relatively few internal combustion engines of greater than 1,000 hp are produced, these engines are responsible for 75 percent of the total NO_x emissions from stationary internal combustion engines. Under 1,000 hp, however, the number of internal combustion engines produced increases tremendously and enforcement of standards of performance would not be feasible in the absence of a certification program similar to that for automobiles. Since the Clean Air Act does not permit standards of performance to be enforced by a certification program, a lower size cutoff of 1,000 hp for standards of performance for stationary internal combustion engines is considered appropriate. Consequently, to be consistent a lower size cutoff of 10.7 gigajoules per hour heat input (about 1,000 hp) is selected for standards of performance for stationary gas turbines. Gas turbines less than 10.7 gigajoules per hour heat input (about 1,000 hp) account for less than 10 percent of the total NO_x emissions from stationary gas turbines. Below this cutoff the standards limiting NO_x and SO_2 emissions would not apply.

Some stationary gas turbines are operated as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation. This type of gas turbine operates infrequently, usually only for checkout and maintenance; therefore, it contributes only a very small amount to total nationwide NO_x emissions. There also could be operational problems with the water injection system due to the long periods of non-operation. Consequently, emergency-standby stationary gas turbines were exempted from standards of performance limiting NO_x emissions.

Stationary gas turbines could contribute to the creation of ice fog, which consists of small ice crystals which are nucleated by airborne particulate. Ice fog occurs at temperatures below −28° C and is a serious problem in only a small portion of the United States, primarily Alaska. Ice fog severely restricts visibility and, since the crystals are long-lived, can plague auto and air traffic for extended periods. The actual impact of water or steam injection into gas turbines on the formation of ice fog is unknown; however, water or steam injection will increase the moisture content of the exhaust gas discharged by gas turbines. Since ice fog occurs only in a small portion of the United States and only under special weather conditions, the impact on air quality due to increased NO_x caused by exempting gas turbines creating ice fog would be minimal. Therefore, gas turbines using water or steam injection for control of NO_x emissions would be exempt from the standards limiting NO_x emissions when ice fog created by the gas turbine is deemed by the owner or operator of the gas turbine to be a traffic hazard.

Stationary gas turbines are sometimes used by the military in combat-type situations. The main advantage of these turbines is their mobility, which would be considerably restricted by a water injection system consisting of either water treatment equipment or a water storage vessel. Restriction of the mobility of these gas turbines could have an adverse effect on national defense; therefore, any military combat-type gas turbine for use in other than a garrison facility is exempt from the standards limiting NO_x emissions.

The possibility of exempting some gas turbines from the standard limiting SO_2 emissions was also examined. Except for exempting all turbines of less than 10.7 gigajoules per hour heat input (about 1,000 hp), no exemptions were considered necessary.

SELECTION OF THE BEST SYSTEM OF EMISSION REDUCTION

There are three possible control techniques for reducing NO_x emissions from stationary gas turbines: wet controls, dry controls, and catalytic exhaust cleanup. Wet controls involve the injection of water or steam into the combustion reaction to reduce peak flame temperatures, thereby reducing NO_x formation. Wet control techniques have been demonstrated on a few large gas turbines (greater than 10,000 hp) used in utility and industrial applications. These installations have had good reliability over long periods of operation. Wet controls, however, have not been applied to small production gas turbines (less than 10,000 hp), although the effectiveness of these techniques for small gas turbines has been demonstrated in laboratory and combustor rig tests. Thus, wet controls can be applied immediately to large stationary gas turbines, but manufacturers estimate that at least three years would be required to incorporate and test wet control techniques on small production gas turbines.

Dry controls consist of operational or design modifications which govern combustion conditions to reduce NO_x formation. Although dry controls have been demonstrated in laboratory and combustor rig tests, manufacturers estimate that up to five years is required for further development, design, test, and incorporation of dry controls on large and small stationary gas turbines.

Catalytic exhaust gas cleanup consists of NO_x reduction by ammonia in the presence of a catalyst. While laboratory tests are very promising, this technique is not demonstrated for stationary gas turbines.

The NO_x emission reduction achievable with wet and dry control techniques clearly favors the development of standards of performance based on wet controls. Reductions in NO_x emissions of more than 70 percent have been demonstrated using wet controls. Dry controls, however, have demonstrated NO_x emission reductions of only about 30 percent.

Standards of performance based on wet controls would reduce national No_x emissions by about 190,000 tons per year in 1982. In contrast, standards of performance based on dry controls would have no impact on national NO_x emissions in 1982, due to the necessity of allowing a five-year delay to incorporate dry controls on gas turbines. By 1987, standards based on wet controls would reduce national NO_x emissions by about 400,000 tons per year, whereas standards based on dry controls would reduce NO_x emissions by only about 90,000 tons per year. Thus, standards of performance based on wet controls would have a much greater impact on national NO_x emissions than standards based on dry controls.

The water pollution impact of standards based on wet controls would be minimal. Water needed for wet controls may be treated by the same processes used to treat steam boiler make-up water. The quality of the wastewater from this treatment is essentially the same as the influent water except that the concentration of total dissolved solids in the effluent stream is 3 to 4 times that of the influent. In most cases, the effluent may be sewered directly or returned to the river supplying the water. Where this is not possible, the effluent may be discharged to an evaporation pond. Consequently, the water pollution impact of standards based on wet controls would be minimal.

The quantity of water required by a stationary gas turbine using wet controls is relatively small. The upper limit water-to-fuel ratio of about 1 :.1 requires only about 5 percent of the quantity of water consumed by a comparable size steam boiler using cooling towers. A water treatment system for five 28 MW stationary gas turbines operating 10 hours per day using a water-to-fuel ratio of 1 : 1, for example, would treat 125,000 gallons of water and reject about 25,000 gallons of wastewater per day. A steam boiler of comparable size with cooling towers would consume 20 times as much water. In fact, the usage rate of water for wet controls is small enough that the unlikely prospect of having to truck water 50 miles was determined to be economically reasonable as discussed below. Standards based on dry controls, however, would have no impact on water pollution or water supplies.

Standards based on wet controls would have a negligible solid waste impact. Also, there would be no adverse noise impact resulting from standards based on either wet or dry controls.

The potential energy impact of standards based on wet controls is small. Standards based on wet controls could increase the fuel consumption of a gas turbine from 0 to 5 percent, depending on the rate of water injection required to comply with the standard. Few turbines will require the high water injection rates (about 1 : 1 water-to-fuel ratios) which result in a 5 percent fuel penalty. Assuming, however, that all stationary gas turbines subject to compliance with standards would require a 1 : 1 water-to-fuel ratio, the energy impact on large stationary gas turbines would be an increase in fuel consumption of about 5500 barrels of fuel oil per day in 1982. The energy impact on small stationary gas turbines would be an increase in fuel consumption of about 7,000 barrels per day of fuel oil in 1987, as a result of the delayed effective date of the proposed standards on small turbines. Each increase represents less than a 0.03 percent increase in projected crude oil consumption in the United States in 1982 and 1987. It should also be recognized that these estimates are based on assumptions which yield the greatest energy impacts. Actual energy impacts are expected to be much lower. The energy impact of standards based on wet controls, therefore, would be minimal. Standards based on dry controls, however, would have no energy impact.

Although wet controls would result in a small adverse impact on gas turbine efficiency, the costs associated with this increased fuel consumption for some applications may be partially offset by an increase in the gas turbine's rated power output capability. aBsed on manufacturer's estimates, gas turbine baseload capacity will be increased by 3 to 4 percent as a result of water injection. In applications where turbines are operated at maximum capacity, such as utility power generation and pipeline compressors stations, this increased baseload capacity essentially reduces the installed costs per kilowatt by the percentage increase in the capacity of the unit, thus slightly reducing the cost impact of standards based on wet controls.

The economic impacts associated with standards based on either wet or dry controls would be small and are considered reasonable. Dry control costs are difficult to quantify. Many manufacturers, however, have indicated that the cost of dry controls would not exceed the cost of wet controls. Consequently, the analysis of the eonomic impact of standards of performance was based on the costs of wet controls and assumes that the costs of dry controls, and hence the economic impact of standards based on dry controls, would be comparable. Standards of performance, therefore, based on either wet or dry controls would increase the capital cost of a gas turbine for most applications by about 1 to 4 percent. For offshore industrial applications where desalinization equipment is required to provide water for wet controls, standards would result in a 7 percent increase in the capital cost of a gas turbine. The annualized costs for a stationary gas turbine in all applications would be increased by about 1 to 4 percent, with utility applications realizing less than a 2 percent increase.

Although it is unlikely that a stationary gas turbine would, of necessity, be installed in an arid area, an analysis was performed which assumed that water would have to be transported to the gas turbine site by truck over a distance of 50 miles. This unlikely situation would result in less than a 4 percent increase in the annualized cost of the gas turbine.

Standards of performance based on wet controls would increase the total capital investment requirements for all industrial and commercial users of large stationary gas turbines (greater than 10,000 hp) by about 36 million dollars by 1982. Total annualised costs would be increased by about 11 million dollars per year in 1982. Standards of performance based on wet controls would have an additional economic impact on users of small stationary gas turbines (less than 10,000 hp) beginning in 1987. Thus, for the period of 1982 through 1987, the capital investment requirements for all stationary gas turbine users would be about 67 million dollars. The total annualised costs would be about 30 million dollars by 1987. These impacts would translate into price increases for the end products or services provided by these industrial and commercial users of stationary gas turbines ranging from less than 0.01 percent in the petroleum refining industry to about 0.1 percent in the electric utility industry. Thus, the economic impact of standards of performance based on wet controls would be very small.

Standards of performance based on dry controls would have no economic impact by 1982. Following 1982, however, the eonomic impact of standards based on dry controls would be comparable to that of standards based on wet controls.

Based on this assessment of the impacts of standards of performance based on wet controls and dry controls, wet controls were selected as the "* * * best system of emission reduction (considering cost) * * *" for reduction of NO_x.

There are two possible control techniques for reducing SO_2 emissions from stationary gas turbines: flue gas desulfurization (FGD) and the firing of low sulfur fuels. FGD, however, would cost about two to three times as much as the gas turbine. The economic impact of standards of performance for stationary gas turbines based on FGD, therefore, is not considered reasonable.

Low sulfur fuels, such as premium distillate oils or natural gas, are now being burned by nearly all stationary gas turbines. These premium fuels are being burned primarily because the increased maintenance costs associated with firing heavy fuel oils are greater than the savings that would be realized by buying these cheaper heavy or residual fuel oils. Over the next five to ten years, however, as oil prices continue to escalate, the price differential between premium distillate fuel oils and heavy fuel oils will probably increase and the economic incentive to burn the premium fuels will probably become marginal.

In this situation and in the absence of regulations requiring stationary gas turbines to fire specific fuels, the choice between firing either premium distillate fuel oils or heavy fuel oils will likely be decided on the basis of the relative convenience and availability of these fuels. Premium distillate fuel oils are more convenient to burn than heavy fuel oils because they have a lower viscosity and are easier to handle. Heavy fuel oils frequently require heating, for example, to reduce their viscosity to the point where they can be readily pumped from one location to another. Even if the price differential between premium distillate fuel oils and heavy fuel oils were to increase to the point where the firing of heavy fuel oils was marginally attractive, the greater inconvenience of scheduling and performing the additional maintenance would probably cause a gas turbine owner or operator to choose to fire the premium distillate fuel oil. On the basis of convenience, therefore, stationary gas turbines are likely to continue firing premium distillate fuel oils even if the economic incentive to do so becomes marginal.

The impact on ambient air quality of standards of performance based on the firing of low sulfur premium distillate fuel oils in gas turbines, therefore, would be negligible. The economic impact would also be negligible for the same reason and there would be no water, energy, solid waste or noise impact associated with standards based on the firing of low sulfur premium distillate fuel oils.

Based on this assessment of the impacts of standards of performance based on the firing of low sulfur fuel oils, this control technique is selected as "* * * the best system of emission reduction (considering costs) * * *" for the reduction of SO_2 emissions.

SELECTION OF FORMAT FOR THE STANDARDS

A number of different formats could be selected to limit NO_x emissions from stationary gas turbines. Mass standards limiting emissions in terms of power output (i.e., mass of emissions per unit of power output) or concentration standards limiting the concentration of emissions in the exhaust gases discharged into the atmosphere could be developed.

While mass standards may appear more meaningful in the sense that they relate directly to the quantity of emissions discharged into the atmosphere, enforcement of mass standards is more costly and the results more subject to error than enforcement of concentration standards.

Concentration standards, however, must be written to insure that the standards are not met merely by addition of dilution air. For combustion processes, this can be accomplished by correcting measured concentration to a reference concentration of O_2 (oxygen). The O_2 concentration in the exhaust gases is related to the excess (or dilution) air. Typical O_2 concentrations in gas turbine exhaust gases are about 15 percent. Thus, referencing standards to 15 percent oxygen effectively precludes circumvention by dilution. Consequently, concentration standards referenced to 15 percent oxygen were selected as the format for standards of performance for stationary gas turbines.

Selection of a concentration format, however, could penalize high efficiency gas turbines. Higher efficiencies are normally achieved by increasing combustor operating pressures and temperatures and NO_x formation generally increases exponentially with increased pressure and temperature. High efficiency turbines, therefore, generally discharge gases with higher NO_x concentrations than low efficiency turbines. A concentration standard based on low efficiency turbines could restrict the use of some high efficiency turbines. Conversely, a concentration standard based on high efficiency turbines could allow such high NO_x concentrations that low efficiency turbines would require no controls. Consequently, having selected a concentration format for standards of performance, an efficiency adjustment factor needed to be selected to permit higher NO_x emissions from high efficiency gas turbines.

NO_x emissions tend to increase exponentially with increased efficiency. It is not reasonable from an emission control viewpoint, however, to select an exponential efficiency adjustment factor. Such an adjustment would at some point allow very large increases in emissions for very small increases in efficiency. The objective of an efficiency adjustment factor should be to give an emission credit for the lower fuel consumption of high efficiency gas turbines. Since the relative fuel consumption of gas turbines varies linearly with efficiency, a linear efficiency adjustment factor is selected to permit increased NO_x emissions from high efficiency gas turbines. A linear efficiency adjustment factor also effectively limits NO_x emissions to a constant mass emission rate per unit of power output.

The efficiency adjustment factor must be referenced to a baseline efficiency. Since most existing simple cycle gas turbines fall in the range of 20 to 30 percent efficiency, 25 percent was selected as the baseline efficiency. The efficiency of stationary gas turbines is usually expressed in terms of heat rate which is the ratio of heat input, based on lower heating value (LHV) of the fuel, to the mechanical power output. The heat rate of a gas turbine operating at 25 percent efficiency is 14.4 kilojoules per watt·hr (10,180 Btu per hp·hr). Thus, the linear adjustment factor as presented in the regulation was selected to permit increased NO_x emissions from high efficiency stationary gas turbines.

The intent of the efficiency adjustment factor is to permit a linear increase in NO_x emissions with increased efficiencies above 25 percent. Consequently, the adjustment factor would not be used to adjust the emission limit downward for gas turbines with efficiencies of less than 25 percent.

The rationale for selection of the format for SO_2 emissions is much the same as that discussed above for NO_x emissions. Thus, to be consistent with the format selected for standards limiting NO_x emissions, a concentration standard is chosen as the format for the SO_2 standard. An emission limit in terms of percent fuel sulfur content has also been included in the SO_2 standard to give the owner or operator the flexibility of either measuring the SO_2 concentration of the exhaust gas or analyzing the fuel being fired in the turbine. Either format for the SO_2 standard can be used since nearly all of the sulfur in the fuel is converted to SO_2.

The efficiency factor associated with the NO_x emission limit would not apply to the SO_2 emission limit, however, because SO_2 emissions do not vary with turbine efficiency.

SELECTION OF THE EMISSION LIMITS

The available data on emission from stationary gas turbines using wet controls come primarily from simple cycle gas turbine and combustor rig tests. No reliable data was available concerning NO_x emissions from regenerative cycle gas turbines using wet controls, although some dry control data was obtained. Careful consideration, therefore, was given to the question of whether regenerative cycle gas turbines could be controlled to the same emission levels as simple cycle gas turbines.

There is general agreement that wet controls will give essentially the same percentage reduction in NO_x emissions from regenerative cycle gas turbines as from simple cycle gas turbines. Thus, the question becomes whether uncontrolled NO_x emissions from regenerative cycle gas turbines are higher than those from simple cycle gas turbines. On first comparison, No_x emissions from regenerative cycle gas turbines appear higher than those from simple cycle gas turbines. Regenerative cycle gas turbines, however, frequently operate at higher thermal efficiencies than simple cycle gas turbines, and when NO_x emissions are plotted against gas turbine thermal efficiency, emissions from regenerative and simple cycle gas turbines do not appear significantly different. As a result, the application of wet controls to either regenerative or simple cycle gas turbines of comparable thermal efficiencies should reduce NO_x emissions to essentially the same level. Consequently, regenerative cycle gas turbines would be subject to the same emission limit as simple cycle gas turbines.

The data also indicate that gas turbines firing gaseous fuels typically have slightly lower controlled NO_x emission levels than gas turbines firing distillate fuels. Again, considering only the data representing major NO_x control efforts, controlled emissions from gas turbines firing gaseous fuels range from about 15 to 50 ppmv, while controlled emissions from gas turbines firing distillate fuels range from about 25 to 60 ppmv. This slight difference in controlled emission levels does not warrant the selection of a separate emission limit for each type of fuel. Only one emission limit, therefore, was selected which applies to gas turbines burning all types of fuel.

Based on this emission data and allowing for some uncertainty in the limited data base, 75 ppmv NO_x corrected to 15 percent oxygen was selected as the numerical emission limit for stationary gas turbines.

The gaseous and premium distillate fuels which have traditionally been burned in stationary gas turbines contain little or no "fuel-bound" or "organic" nitrogen. However, heavy residual fuel oils and crude oils can contain high levels of fuel-bound nitrogen. Total NO_x emissions from any combustion source, including stationary gas turbines, are a function of both thermal NO_x and organic NO_x formation. Thermal NO_x is formed in a well defined high temperature reaction between nitrogen and oxygen from the combustion air. Organic NO_x, however, is formed by the combination of fuel-bound nitrogen with oxygen during combustion. The reaction mechanism is not fully understood. Wet controls are effective for reducing thermal NO_x, but are not effective for reducing organic NO_x.

Three alternatives were considered to address the fuel-bound nitrogen contribution to total NO_x emissions from stationary gas turbines. The first alternative would have exempted heavy or residual fuel oils from standards of performance. This approach would have allowed gas turbines firing heavy residual fuel oils to operate with no emission controls. In addition to the difficulties of distinguishing between premium and residual fuel oils in the standards, this approach would have encouraged owners or operators to burn heavy or residual fuel oils as a means of evading standards of performance.

The second alternative would have been to base standards of performance on the firing of low nitrogen fuels. This approach would have required emission controls on all new, modified, and reconstructed stationary gas turbines, but would have effectively precluded the firing of fuels other than those premium gaseous and distillate fuels which turbines are now using. Firing of heavy or residual fuel oils would have required major breakthroughs in controlling organic NO_x formation, or additional refining of these fuels to reduce their nitrogen content (as well as their sulfur content) to a level equivalent to that of premium distillate fuels.

The third alternative would include an adjustment to the NO_x emission limit as a function of the fuel-bound nitrogen level in the fuel fired. This approach would require NO_x controls on all new stationary gas turbines, but would not restrict new, modified or reconstructed gas turbines to firing premium gaseous and distillate fuels. Thus, stationary gas turbines would not be penalized for firing heavy fuel oils, nor would there be any added impetus toward the firing of heavy or residual fuel oils in order to evade standards of performance.

As discussed earlier, low sulfur fuels, such as premium distillate fuel oils or natural gas are now being fired by nearly all stationary gas turbines. These premium fuels are being fired primarily because the increased maintenance costs associated with firing heavy fuel oils are greater than the savings that would be realized by buying these less expensive heavy or residual fuel oils. Over the next five to ten years, however, as oil prices continue to escalate, the price differential between premium distillate fuel oils and heavy fuel oils will probably increase and economic incentive to fire the premium fuel oils will probably become marginal. It is also possible that there could be limited supplies of premium distillate fuel oils over the next five to ten years due to declining production of oil and natural gas in the United States, increased demands for these premium fuels by users other than gas turbines which cannot utilize heavy or residual fuel oils, and the uncertainty of additional crude oil supplies in the world energy markets. In fact, in anticipation of the possibility of limited supplies of premium distillate fuel oils, approximately 50 percent of the new gas turbines on order are being designed to allow the owner or operator the flexibility of firing either premium distillate fuel oils, or residual or heavy fuel oils. Consequently, in order to provide gas turbine owners and operators the flexibility to fire either premium or heavy and residual fuels, but to ensure that standards of performance add no impetus toward the firing of heavy fuel oils as a means of evading standards, alternative three is selected for standards of performance limiting NO_x emissions from stationary gas turbines.

An allowance in the NO_x emission limit dependent on fuel-bound nitrogen level with no upper limit on emissions, however, could permit extremely high NO_x emissions when fuels with very high nitrogen contents are fired. Thus, it is essential that restraints be placed on such an emission allowance. Therefore, a fuel-bound nitrogen allowance was developed that allows approximately 50 percent availability of the heavy fuel oils. This corresponds to a fuel-bound nitrogen content of 0.25 percent. Firing a fuel with 0.25 percent nitrogen content increases controlled NO_x emissions by about 50 ppm.

The effect of ambient atmospheric conditions on NO_x emissions from stationary gas turbines is substantial. Large changes in relative humidity, for example, can cause NO_x emissions to vary by a factor of 2 or more. In order to insure that standards of performance are enforced uniformly, therefore, the effect of ambient atmospheric conditions was derived by extracting the common elements from several ambient condition corrrection factors proposed by gas turbine manufacturers. This correction factor, therefore, represents the general effect of ambient atmospheric conditions on NO_x emissions. Consequently, the ambient condition correction factor, as presented in the regulation, or an alternative correction factor as discussed below, will be used to adjust measured NO_x emissions during any performance test to determine compliance with the numerical emission limit.

As an alternative, gas turbine manufacturers, owners, or operators may elect to develop custom ambient condition correction factors for adjusting measured NO_x emissions from particular gas turbine models to ISO standard ambient conditions of pressure (101.3 kilopascals), humidity (60 percent relative humidity), and temperature (288 degrees Kelvin). Some gas turbine manufacturers have proposed ambient condition correction factors which include variables such as fuel-to-air ratios and combustor temperatures. These variables are difficult to measure and are operating parameters which may vary widely due to factors other than ambient conditions. For this reason, any custom ambient condition correction factor must be developed in terms of the following variables only: combustor inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. All ambient condition correction factors must be substantiated with data and then approved for use by EPA before they can be used in determining compliance with the NO_x emission limit. Ambient condition correction factors will be applied to all performance tests, not only those in which the use of such factors would reduce measured emission levels.

Some delay is required before the NO_x standard of performance can be applied to small stationary gas turbines. A delay is necessary to provide time for manufacturers to incorporate NO_x controls on their small production stationary gas turbine models. It is estimated that about three years delay in the effective date of the standard for small stationary gas turbines would be required to allow manufacturers time to incorporate and test wet controls on these gas turbines. Some manufacturers have expressed optimism at being able to meet the NO_x standards using dry controls if given about five years delay. Since small gas turbines represent only about 10 to 15 percent of the total NO_x emissions from stationary gas turbines, the difference in environmental impact of a three-year versus five-year delay would be small. Additionally, a three-year delay would essentially force these manufacturers to incorporate wet controls, whereas a five-year delay would provide the flexibility to use wet controls or to develop and use dry controls. Consequently, five years was selected as the delay period for implementation of the NO_x emission limit on small stationary gas turbines.

In selecting the size cutoff to differentiate between large and small stationary gas turbines, consideration was given to the purpose for the cutoff and the effect on competitive markets. The purpose of the cutoff is to differentiate between large gas turbines where wet controls have been commercially demonstrated and small gas turbines where wet controls although effective, have not been generally applied on a commercial basis. Consideration of the market data reveals that there are two major competitive markets for stationary gas turbines which can be generally described as small gas turbines and large gas turbines. The size range of 5000 to 10,000 horsepower essentially separates these two markets. All gas turbines above this range are manufactured by companies which have developed wet control systems for their stationary gas turbines. The size cutoff, therefore, between small and large gas turbines was selected as the upper end of this range. Thus, large stationary gas turbines are defined as those with heat input at peak load of greater than 107.2 gigajoules per hour (approximately 10,000 horsepower for a 25 percent efficient gas turbine).

The best system of emission reduction, considering costs, selected for SO_2 emissions was the firing of low sulfur fuel oils. To be consistent with the objective of the fuel-bound nitrogen allowance NO_x emission limit and allow for approximately 50 percent availability of the residual and heavy fuel oils, the SO_2 emission limit is selected as 150 ppm referenced to 15 percent O_2 which corresponds to a fuel sulfur content of 0.8 percent by weight.

The five-year delay of the NO_x emission limit applied to small gas turbines (less than 10,000) to provide manufacturers time to incorporate wet controls onto their turbines would not apply to the SO_2 emission limit since the control technique of burning low sulfur fuels is now available to all turbines.

It should be noted that standards of performance for new sources established under Section 111 of the Clean Air Act reflect emission limits achievable with the best adequately demonstrated systems of emission reduction considering the cost of such systems. State implementation plans (SIP's) approved or promulgated under Section 110 of the Act, on the other hand, must provide for the attainmnt and maintenance of National Ambient Air Quality Standards (NAAQS) designed to protect public health and welfare. For that purpose SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources. For example, EPA's Interpretative Ruling (41 FR 55524, December 21, 1976) on the construction of a new or modified source in an area that exceeds a NAAQS requires, among other things, that the new source must meet an emission limitation which reflects the "lowest achievable emission rate" for such type of source. At a minimum, the lowest rate achieved in practice would have to be specified unless the applicant can demonstrate that it cannot achieve such a rate. In no event could the rate exceed any applicable standard of performance for new sources.

This stringent requirement reflects EPA's judgment that a new source should be allowed to emit pollutants into an area violating a NAAQS only if its contribution to the violation is reduced to the greatest degree possible. While the cost of achievement may be an important factor in selecting a standard of performance for new sources applicable to all areas of the country, the cost factor must be accorded far less weight in determining an appropriate emission limitation for a source locating in an area violating statutorily-mandated health and welfare standards. Thus, while there may be technology available for new sources which have been determined not to be appropriate for standards of performance because of the consideration given to costs, this technology would be considered for purposes of determining the "lowest achievable emission rate" for such type of sources. Consequently, standards of performance for new sources should not be viewed as the ultimate in achievable control and should not limit the imposition of a more stringent standard, where apppropriate.

States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111, or those necessary to attain or maintain the NAAQS under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

SELECTION OF MONITORING REQUIREMENTS

To provide a convenient means for enforcement personnel to insure that an emission control system installed to comply with standards of performance is properly operated and maintained, monitoring requirements are generally included in standards of performance. For stationary gas turbines, the most straightforward means of insuring proper operation and maintenance is to monitor emissions released to the atmosphere.

EPA has establishing NO_x monitoring performance specifications in Appendix B of 40 CFR Part 60 for large industrial sources with well developed velocity and temperature profiles. Stationary gas turbines, however, do not have well developed velocity and temperature profiles in all cases. Gas stratification of the turbine exhaust, for example, makes the location of the sample point critical. Also, since some gas turbines are started remotely from a central location, special systems and data reporting procedures would be necessary to start and maintain continuous monitors.

Currently there are no NO_x continuous monitors operating on gas turbines, and resolution of these sampling problems and development of performance specifications for continuous monitoring systems would entail a major development program. For these reasons, continuous monitoring of NO_x emission from gas turbines would not be required by the proposed standards.

An effective means of ensuring operation of the water injection system used to control NO_x emissions from gas turbines is to monitor the water-to-fuel ratio being fed to the turbine. Both water and fuel monitors are readily available and are demonstrated technology for use on gas turbines. Consequently, to ensure operation of water injection systems, the proposed standards for stationary gas turbines would require continuous monitoring of the water-to-fuel ratio where water injection is employed to comply with NO_x standard.

Also, an effective means of ensuring the firing of fuels with the proper nitrogen content to control NO_x emissions caused by fuel bound nitrogen is to monitor the nitrogen content of the fuel being fired. Consequently, any owner or operator that uses the fuel-bound nitrogen allowance to comply with NO_x emission limit will be required by the standard to monitor the nitrogen content of the fuel.

The continuous monitoring of SO_2 emissions would not be required by the proposed standards for the same reasons continuous monitoring of NO_x emissions would not be required. A means of ensuring the firing of low sulfur fuels to control SO_2 emissions, however, is to monitor the sulfur content of the fuel being burned. This is already a common practice among gas turbine users. Consequently, to ensure the use of low sulfur fuels by stationary gas turbines to comply with the SO_2 emission limit, the standard would require monitoring the sulfur content of the fuel.

SELECTION OF PERFORMANCE TEST METHODS

Reference Method 20, "Determination of Nitrogen Oxides, Sulfur Dioxide, and Oxygen Emissions from Stationary Gas Turbines," was selected as the performance test method to determine compliance with the standards of performance limiting NO_x emissions for stationary gas turbines. This test method is based on the EPA gas turbine field tests and on background data for continuous monitoring system specifications (FEDERAL REGISTER, October 6, 1975). Reference Method 20 includes (1) measurement system design criteria, (2) measurement system performance specifications and performance test procedures, and (3) procedures for emission sampling. The performance specifications include the span drift, zero drift, linearity check, response time of the system, and interference checks. This method allows a choice of instruments and will provide reliable data if the performance specifications are met.

Both the Society of Automotive Engineers (SAE) and Mobile Source test methods are acceptable alternative methods, if the selected instrument models are capable of meeting the performance specifications of Reference Method 20.

NO_x emission measured by Reference Method 20 will be affected by ambient atmospheric conditions. Consequently, measured NO_x emissions would be adjusted during any performance test by the ambient condition correction factor discussed earlier, or by custom correction factors approved for use by the Administrator.

In order to apply the fuel-bound nitrogen allowance included as part of the NO_x emission limit, the nitrogen content of the fuel must be determined. The analytical methods and procedures employed to determine the nitrogen content of the fuel would be approved by the Administrator and would be accurate to within plus or minus five percent.

In lieu of determining the SO_2 concentration of the exhaust gas from a gas turbine by using Method 20, compliance with the standard may be demonstrated by determining the sulfur content of the fuels being used by the gas turbine. Sulful content of the fuel will be determined using ASTM D2880–71 for liquid fuels and ASTM D1072–70 for gaseous fuels.

MISCELLANEOUS

As prescribed by Section 111 of the Act, this proposal of standards has been preceded by the Administrator's determination that emissions from stationary gas turbines contribute to air pollution which causes or contributes to the endangerment of public health or welfare, and by his publication of this determination in this issue of the FEDERAL REGISTER. In accordance with Section 117 of the Act, publication of these proposed standards was preceded by consultation with appropriate advisory committees, independent experts and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulations, including the designation of stationary gas turbines as a significant contributor to air pollution which causes or contributes to the endangerment of public health or welfare, economic and technological issues, and on the proposed test methods.

Comments are also specifically invited no the severity of the economic impact of the proposed standards on stationary gas turbines located offshore, since a number of interested parties have expressed objection to not exempting the offshore turbine from compliance with the standard. Any comments submitted to the Administrator on this issue, however, should contain specific information and data pertinent to an evaluation of the magnitude of this impact and its severity.

Economic impact analysis: The criteria for an action to be considered major, thereby requiring development of an Economic Impact Analysis (EIA) are: (1) an increase in the fifth-year annualized costs of 100 million dollars, (2) a major product price increase of 5 percent, or (3) an increase in national energy consumption of 25,000 barrels of fuel oil per day. The impacts resulting from the proposed standards would not exceed these criteria, except possibly for those stationary gas turbines sold for offshore oil and gas drilling platforms, where the proposed standards could increase the price of a gas turbine by about 7 percent. Most gas turbines used in the application, however, are likely to have a heat input at peak capacity of less than 107.2 gigajoules per hour (about 10,000 horsepower). Consequently, they would be considered small gas turbines and would be exempt from the standards for five years following proposal of the standards. In any event, however, stationary gas turbines sold for offshore applications constitute such a small percentage (estimated at less than 3 percent) of the overall market for stationary gas turbines that they are not considered a major product within the meaning of the 5 percent major product price increase criteria for an action to be considered major, thereby requiring preparation of an EIA. The Environmental Protection Agency has determined, therefore, that his proposed action does not constitute a major action requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A–107.

Dated: September 21, 1977.

DOUGLAS M. COSTLE,
Administrator.

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

1. By adding subpart GG as follows:

Subpart GG—Standards of Performance for Stationary Gas Turbines

Sec.
60.330 Applicability and designation of affected facility.
60.331 Definitions.
60.332 Standard for nitrogen oxides.
60.333 Standard for sulfur dioxide.
60.334 Monitoring of operations.
60.335 Test methods and procedures.

AUTHORITY: Sections 111 and 301(a) of the Clean Air Act, as amended, [42 U.S.C. 1857c-7, 1857g(a)], and additional authority as noted below.

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities: all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Stationary gas turbine" means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self-propelled. It may, however, be mounted on a vehicle for portability.

(b) "Simple cycle gas turbine" means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) "Regenerative cycle gas turbine" mean any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlent combustion air to the gas turbine.

(d) "Combined cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) "Emergency gas turbine" means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) "Ice fog" means an atmospheric suspension of highly reflective ice crystals.

(g) "ISO standard day conditions" means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) "Efficiency" means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) "Peak load" means 100 percent of the manufacturer's design capacity of the gas turbine.

(j) "Base load" means the load level at which a gas turbine is normally operated.

(k) "Fire-fighting turbine" means any stationary gas turbine that is used primarily to pump water for extinguishing fires.

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere, except as provided in paragraphs (b), (c), and (d) of this section.

(1) From any gas turbine with a heat rate at peak load of more than or equal to 14.4 kilojoules per watt hour, based on the lower heating value of the fuel fired, any gases which contain nitrogen oxides in excess of:

$$STD=0.0075+F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(2) From any gas turbine with a heat rate at peak load of less than or equal to 14.4 kilojoules per watt hour, based on the lower heating value of the fuel fired, any gases which contain nitrogen oxides in excess of:

$$STD=0.0075\left(\frac{14.4}{Y}\right)+F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at peak load (kilojoules per watt hour).

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F *(NO_x, percent by volume)*
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	$0.04(N)$
$0.1 < N \leq 0.25$	$0.004+0.0067(N-0.1)$
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

(b) Stationary gas turbines with a heat input at peak load of 107.2 gigajoules per hour (100 million Btu/hour) or less, based on the lower heating value of the fuel fired, are exempt from paragraph (a) of this section for a period not to exceed five years from (date of proposal).

(c) Stationary gas turbines using water or steam injection for control of NO_x emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(d) Emergency standby gas turbines, military gas turbines for use in other than a garrison facility, and fire-fighting gas turbines are exempt from paragraph (a) of this section.

§ 60.333 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) The sulfur content of the fuel fired by the gas turbine may be used to determine compliance with paragraph (a) of this section. Under such circumstances, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

§ 60.334 Monitoring of operations.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to withn ±5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall record daily the sulfur content, nitrogen content, and lower heating value of the fuel being fired in the gas turbine.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with § 60.332 by the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under § 60.335(a).

(2) Sulfur dioxide. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9)).

§ 60.335 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.332 as follows:

(1) Reference Method 20 for the concentration of nitrogen oxides and oxygen.

(i) The nitrogen oxides emission level measured by Reference Method 20 shall be adjusted to ISO standard day conditions by the following ambient condition correction factor:

$$NO_x=(NO_{x_{obs}})\left(\frac{P_{ref}}{P_{obs}}\right)^{0.5}e^{19(H_{obs}-0.00633)}$$

where:

NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x_{obs}}$ = measured NO_x emissions at 15 percent oxygen, ppmv.

P_{ref} = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure.

P_{obs} = measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = specific humidity of ambient air at test.

e = transcendental constant (2.718).

The adjusted NO_x emission level shall be used to determine compliance with § 60.332.

(ii) Manufacturers, owners or operators may develop custom ambient condition correction factors in terms of combustor inlet pressure, ambient air pressure, ambient air humidity and ambient air temperature to adjust the nitrogen oxides emission level measured by the performance test as provided for in § 60.8 to ISO standard day conditions. These ambient condition correction factors shall be substantiated with data and must be approved for use by the Administrator before they can be used to determine compliance with paragraph (a) of this subpart. Notices of approval of custom ambient condition correction factors will be published in the Federal Register.

(iii) The water-to-fuel ratio necessary to comply with § 60.332 will be determined during the initial performance test by measuring NO_x emissions using Reference Method 20 and the water-to-fuel ratio necessary to comply with § 60.332 at 30, 50, 75, and 100 percent of peak load.

(2) ASTM D-2382 for the lower heating value of liquid fuels and ASTM D-1826 for the lower heating value of gaseous fuels. These methods shall also be used to comply with § 60.334(b).

(3) The analytical methods and procedures employed to determine the nitrogen content of the fuel being fired shall be approved by the Administrator and shall be accurate to within plus or minus five percent.

(b) The method for determining compliance with § 60.333, except as provided in § 60.8(b), shall be as follows:

(1) Reference Method 20 for the concentration of sulfur dioxide and oxygen.

(2) ASTM D2880-71 for the sulfur content of liquid fuels and ASTM D1072-70 for the sulfur content of gaseous fuels. These methods shall also be used to comply with § 60.334(b).

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

Appendix A—Reference Methods

2. Part 60 is amended by adding Reference Method 20 to Appendix A as follows:

* * * * *

METHOD 20—DETERMINATION OF NITROGEN OXIDES, SULFUR DIOXIDE, AND OXYGEN EMISSIONS FROM STATIONARY GAS TURBINES

1. *Principle and Applicability.*

1.1 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of nitrogen oxides (NO_x) and oxygen (O_2) content. During each NO_x and O_2 determination, a separate measurement of sulfur dioxide (SO_2) emissions is made, using Method 6, or its equivalent. The O_2 determination is used to adjust the NO_x and SO_2 to a reference condition.

1.2 Applicability. This method is applicable for the determination of nitrogen oxide, sulfur dioxide, and oxygen emissions from stationary gas turbines. For the NO_x and O_2 determinations, this method includes: (1) Measurement system design criteria, (2) analyzer performance specifications and performance test procedures; and (3) procedures for emission testing.

2. *Apparatus and Reagents*

2.1 Measurement System. The equipment required to extract, transport, and analyze the gas sample constitutes the "measurement system." A schematic of the measurement system is shown in Figure 20-1. (Measurement system performance specifications are described in detail in Section 3.) The essential components of the measurement system are described below.

2.1.1 Probe. Stainless steel type 316 or equivalent, to transport gas from stack.

2.1.2 Particulate Filter. A filter is used to remove particulates ahead of the calibration valve assembly. In most cases, either in-stack or out-stack filter location is acceptable; however, out-stack filtration is required when the sample gas temperature is above 500°C (930°F). The filtration temperature shall be at least 120°C (250°F) to prevent moisture condensation. Glass fiber filters, of the type specified in EPA Method 5, or equivalent, are recommended.

2.1.3 Calibration Valve Assembly. A three-way valve assembly is used to direct the zero and span calibration gases to the analyzers. This assembly shall be located directly behind the probe and filter and shall be capable of blocking the sample gas flow and introducing the span and zero gases when the system is in the calibration mode.

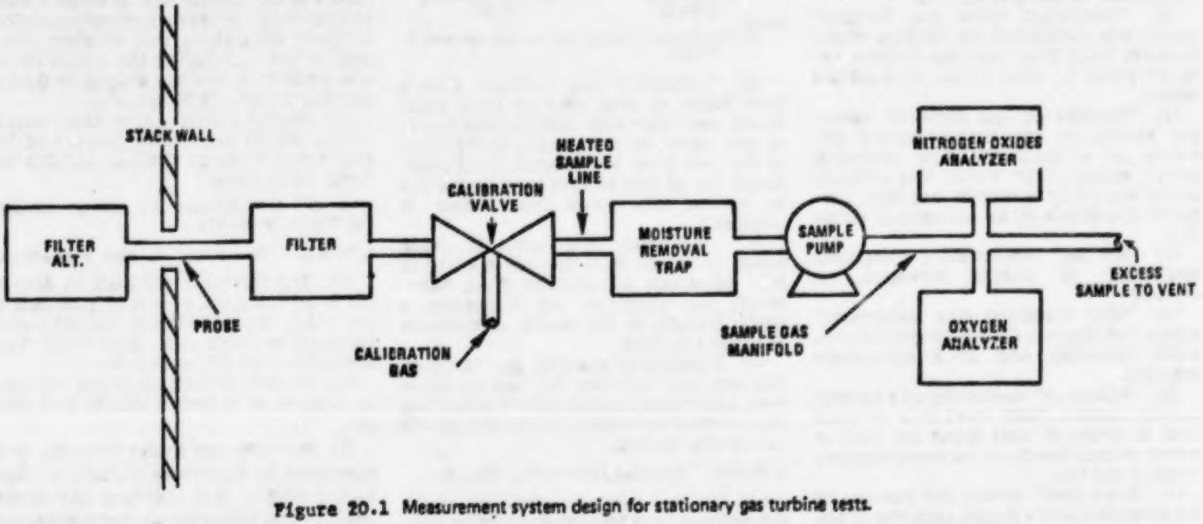

Figure 20.1 Measurement system design for stationary gas turbine tests.

2.1.4 Calibration Gases. Calibration gases are used to perform zero, span and calibration checks of the analyzers during each test run. The concentrations and specifications of these gases are described in detail in Sections 2.2 and 6.2.

2.1.5 Heated Sample Line. A FEP fluorocarbon or stainless steel (type 316 or equivalent) sample line is used to transport the gases to the sample conditioner and analyzers. The sample gas shall be maintained at least 5°C (10°F) above the stack gas dew point to prevent moisture condensation.

2.1.6 Moisture Trap. A moisture trap, designed to reduce the dew point of the sample gas to 3°C (37°F) or less, is used. For instruments not affected by water vapor, this device is not required; however, the moisture content shall be determined using methods subject to the approval of the Administrator and the NO_x and O_2 concentrations shall be corrected to a dry gas basis.

2.1.7 Pump. A nonreactive leak-free sample pump is used to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from or coated with nonreactive material (FEP fluorocarbon or type 316 stainless steel).

2.1.8 Sample Gas Manifold. A sample gas manifold is recommended for diverting portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, FEP fluorocarbon, or stainless steel (type 316 or equivalent). Instead of using the manifold, separate sample lines may be connected to each analyzer.

2.1.9 Oxygen Analyzer. An oxygen analyzer is used to determine the oxygen concentration (percent O_2) of the sample gas stream.

2.1.10 Nitrogen Oxides Analyzer. A NO_x analyzer is used to determine the ppm concentration of nitrogen oxides in the sample gas stream.

2.1.11 Sulfur Dioxide Analysis. Method 6 apparatus, or equivalent, is required for sulfur dioxide determination.

2.2 Calibration Gas Specifications.

2.2.1 Zero Gas. Prepurified nitrogen is used.

2.2.2 Nitrogen Oxide Calibration Gases. Mixtures of known concentrations of NO in nitrogen are required. Nominal NO concentrations of 25, 50, and 90 percent of the instrument full scale range are needed. The 90 percent gas mixture is used to set and chack the instrument span and is referred to as span gas. The 25 and 50 percent gas mixtures shall be used to validate the analyzer calibration, prior to each test.

2.2.3 Oxygen Calibration Gases. Ambient air at 20.9 percent oxygen shall be used as the span gas (high range concentration gas). A midscale calibration gas (approximately 13 percent O_2 in nitrogen) shall be used to validate the analyzer calibration prior to each test.

2.2.4 Concentration Validation. Within one month prior test use, calibration gases shall be analyzed, by the appropriate test method specified in Section 6.2, to determine their true concentration levels. Gas concentrations that are traceable to the National Bureau of Standards and which can be demonstrated to be stable are exempted from the analysis requirements.

3. *Measurement System Performance Specifications and Performance Test Procedures.*

3.1 Analyzer. "Span" is defined as the concentration range (specified by manufacturer) over which an analyzer will give valid readings. The spans for the analyzers used in this method shall be as follows:

3.1.1 Oxygen Analyzer: 0 to 25% O_2.

3.1.2 NO_x Analyzer: 0 to 120 ppm.

3.2 Analyzer Interferences and Interference Response. The "interference response" of an analyzer is defined as the output response to a component in the sample gas stream, other than the gas component being analyzed; the analyzers used in this method shall not have a total interference response of more than ±2 percent of span.

Particulate matter and water vapor are the primary interfering species for most instrumental analyzers, but these may be removed physically by using filters and condensers. Other possible specific interferents found in turbine exhaust streams include carbon monoxide, carbon dioxide, nitrogen oxides, sulfur dioxide and hydrocarbons. Each analyzing instrument may respond to one or more of these interferents in ways that alter the desired measurement.

The interference response of an analyzer is determined by measuring the total analyzer response to the gaseous components (or mixtures) listed in Table 20.1; these gases may either be introduced into the analyzer separately, or as a single gas mixture. The total interference output response of the analyzer to these components, if any, shall be determined (in concentration units). The values obtained in an interference response test shall be recorded on a form similar to Figure 20.2.

TABLE 20.1 INTERFERENCE TEST GAS CONCENTRATIONS

CO	500 ppm
SO_2	200 ppm
NO/NO_2	200 ppm
CO_2	10%
O_2	20.9% (Air)

FIGURE 20.2 INTERFERENCE RESPONSE

Date of Test:______________________

Analyzer Type:______________________ S/N______________

Test Gas Type	Conc.	Analyzer Output Response	% of Span

$$\% \text{ of Span} = \frac{\text{Analyzer Output Response}}{\text{Instrument Span}} \times 100$$

If the sum of the interference responses of the test gases is greater than 2 percent of the instrument span, the analyzer shall not be used in the measurement system of this method.

An interference response test of each analyzer shall be conducted prior to its initial use in the field. Thereafter, if changes are made in the instrumentation which could alter the interference response, e.g., changes in the type of gas detector, the instruments shall be retested.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20.1 the interference performance specification is not exceeded, are acceptable. If these data are not available, the tests shall be made.

3.3 Analyzer Response Time. When a change in pollutant concentration occurs at the inlet of the measurement system (i.e., at probe), the change is not immediately registered by the analyzer; "response time" is defined as the amount of time that it takes for the analyzer to register a concentration value within 5 percent of the new inlet concentration. The maximum response time for the analyzers used in this method is three minutes.

To determine response time, first introduce zero gas into the system until all readings are stable; then, introduce span gas into the system. The amount of time that it takes for the analyzer to register 95 percent of the final span gas concentration is the upscale response time. Next, reintroduce zero gas into the system; the length of time that it takes for the analyzer output to come within 5 percent of the final reading is the downscale response time. The upscale and downscale response times shall each be measured three times. The readings shall be averaged, and the average upscale or downscale response time, whichever is greater, shall be reported as the "response time" for the analyzer. Response time data are recorded on a form similar to Figure 20.3. A response time test shall be conducted prior to the initial field use of the measurement system, and shall be repeated if changes are made in the measurement system.

3.4 Zero Drift. "Zero drift" is the change in analyzer output during a turbine performance test, when the input to the measurement system is a pure grade of nitrogen (zero gas). The maximum allowable zero drift for the analyzers used in this method is ±2 percent of the specified instrument span. The zero drift calculation is made for each gas for each turbine test run; this is done by taking the difference of the zero gas concentration values measured at the start and finish of the test (see Section 6.1). The zero drift is recorded as a percentage of the instrument span) on a form similar to Figure 20.4.

3.5 Span Drift. "Span drift" is the change in the analyzer output during a turbine performance test, when the input to the measurement system is span gas. The maximum allowable span drift for the analyzers used in this method is ±2 percent of the specified instrument span. The span drift calculation is to be made for each gas for each turbine test run; this is done by taking the difference between the span gas concentration values measured at the beginning and end of the test. Span drift is recorded (as a percentage of instrument span) on a form similar to Figure 20.4. Span drift must be corrected for any zero drift that occurred during the test period (see Figure 20.4).

4. *Procedure for Field Sampling.*

4.1 Selection of a Sampling Site and the Minimum Number of Traverse Points.

RESPONSE TIME

Date of Test________________

Analyzer Type________________ S/N________________

Span Gas Concentration__________ ppm

Analyzer Span Setting__________ppm

Upscale
1__________seconds
2__________seconds
3__________seconds

Average upscale response ________seconds

Downscale
1__________seconds
2__________seconds
3__________seconds

Average downscale response________seconds

System response time = slower average time = ________seconds.

Figure 20.3

TURBINE SAMPLING SYSTEM

Zero and Span Drift Data

Turbine Type ________________ S/N________________

Date:________________

Test No.:________________

Analyzer: Type________________ S/N________________

	Initial Calibration ppm or %	Final Calibration ppm or %	Difference Initial-Final ppm or %	% of Span
Zero Gas				
High Calibration Gas (Span Gas)			*	

$$\% \text{ of Span} = \frac{\text{Absolute Value of Difference}}{\text{Instrument Span}} \times 100$$

*Corrected for zero drift, i.e., if zero drift over test period is +2 ppm then 2 ppm shall be subtracted from the difference between the initial and final readings.

Figure 20.4

4.1.1 Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler.

4.1.2 The minimum diameter of the sample ports shall be 3-inch nominal pipe size (NPS).

4.1.3 The minimum number of points for the preliminary O_2 sampling (Section 8.3.2) shall be as follows: (1) eight, for stacks having cross-sectional areas less than 1.5 m^2 (16.1 ft^2); (2) one sample point for each 0.2 m^2 (2.2 ft^2) of area, for stacks of 1.5 m^2 to 10.0 m^2 (16.1–107.6 ft^2) in cross-sectional area; and (3) one sample point for each 0.4 m^2 (4.4 ft^2) of area, for stacks greater than 10.0 m^2 (107.6 ft^2) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20.2; therefore, round off the number of points (upward), when appropriate.

TABLE 20.2.—*Cross-sectional layout for rectangular stacks*

No. of traverse points:	*Matrix layout*
9	3×3
12	4×3
16	4×4
20	5×4
25	5×5
30	6×5
36	6×6
42	7×6
49	7×7

4.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary O_2 sampling has been determined, use Method 1 to locate the traverse points.

4.3 Measurement System Operation.

4.3.1 Preliminaries.

4.3.1.1 Prior to the turbine test, the measurement system shall have been demonstrated to have met the performance specifications for interference response and response time described in Sections 3.2 and 3.3.

4.3.1.2 Turn on the sample pump and instruments; allow the normal warmup time required for stable instrument operation.

4.3.1.3 After the instruments have stabilized, the measurement system shall be calibrated using the procedures detailed in Section 6.1. Transfer the zero and span gas calibration data from Figure 20.5 to a form similar to Figure 20.4.

4.3.1.4 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20.6. Also, record the location and number of the traverse points on a diagram.

4.3.2 Preliminary Oxygen Sampling.

4.3.2.1 At the start of a 3-run sample sequence, position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of O_2 at each point and record the data on Figure 20.7.

Figure 20.5

CALIBRATION DATA

Date____________________

Analyzer Type____________________ S/N____________________

High Range Gas Conc.______________ % Full Scale______________

Mid Range Gas Conc.______________ % Full Scale______________

Low Range Gas Conc.______________ % Full Scale______________

Zero Gas______________ % Full Scale______________

Figure 20.6

STATIONARY GAS TURBINE

TURBINE OPERATION RECORD

Test Operator____________________ Date____________________

Turbine ID Type____________________

Turbine ID S/N____________________

Location Plant____________________

Location City____________________

Ambient Temperature____________________

Ambient Humidity____________________

Test Time Start____________________

Test Time Finish____________________

Fuel Flow Rate____________________*

Water or Steam Flow Rate____________________*

Ambient Pressure____________________

Ultimate Fuel Analysis

C______________

H______________

O______________

N______________

S______________

Ash______________

H_2O______________

Trace Metals

____

Na______________

Va______________

K______________

etc.**______________

Operating Load____________________

*Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

**i.e., Additional elements added for smoke suppression.

FIGURE 20.7

Preliminary Oxygen Traverse

Location ____________ Date ____________

Plant ____________________

City, State ____________________

Turbine ID

Mfg. ____________________

Model, serial number ____________________

Sample Point	Oxygen Concentration

4.3.2.2 Select the eight sample points at which the lowest oxygen concentrations were obtained. These same points shall be used for all three runs which comprise the emission test. More points may be used, if desired.

4.3.3 Emission Sampling.

4.3.3.1 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be 3 minutes plus the average system response time. Determine the average steady-state concentration of O_2 and NO_x a each point and record the data on Figure 20.8.

4.3.2.2 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and span drift, as described in Sections 3.4 and 3.5. If the zero and/or span drift exceed ±2.0 percent the run may be considered invalid, or may be accepted provided the calibration data which results in the highest corrected emission concentration is used.

4.3.2.3 If additional turbine runs are conducted within 4 hours of the previous run, an initial calibration of the measurement system is not required. If more than 4 hours have elapsed between runs, the pre-test calibration shall be done.

4.4 An SO_2 determination shall be made (using Method 6, or equivalent) during the test. A minimum of six total points, selected from those required for the NO_x measurement, shall be sampled; two points shall be used for each sample run. The sample time at each point shall be at least 10 minuets. The oxygen readings taken during the NO_x test runs corresponding to the SO_2 traverse points (see Section 4.3.3.1) shall be averaged, and this average oxygen concentration shall be used to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20-1).

Figure 20.8

STATIONARY GAS TURBINE
GAS SAMPLE POINT RECORD

Turbine ID
Mfg.____________________
Model & S/N________________
Plant____________________
Location
City____________________
State____________________
Ambient Temp.________________
Ambient Press________________
Ambient Humidity______________
Date______________________
Test Time Start______________
Test Time Finish_____________

Test Operator Name____________________
O_2 Instrument Type__________S/N__________
NO_x Instrument Type__________S/N__________

Sample Point	Time (Min)	O_2* (%)	NO_x* (ppm)
1	0		

*Average steady state value from recorder or instrument readout.

5. Emission Calculations.

5.1 Correction to 15 Percent Oxygen. Using Equation 20-1, calculate the NO_x and SO_2 concentrations (adjusted to 15 percent O_2). The correction to 15 percent oxygen is sensitive to the accuracy of the oxygen measurement. At the level of analyzer drift specified in the method (±2 percent of full scale), the change in the oxygen concentration correction can exceed 10 percent when the oxygen content of the exhaust is above 16 percent O_2. Therefore O_2 analyzer stability and careful calibration are necessary.

$$\text{Actual pollutant concentration } (NO_x \text{ or } SO_2) \times \frac{5.9\%}{20.9\% - O_2\% \text{ actual}} = \text{Pollutant concentration adjusted to } 15\%\ O_2$$

where:

5.9% is 20.9%−15% (the defined concentration basis).

O_2 actual is the sample point oxygen concentration for NO_x calculation, and the average O_2 concentration for SO_2 calculation.

5.2 Calculate the average adjusted NO_x concentration by summing the point values and dividing by the number of sample points.

6. Calibration.

6.1 Measurement System. Prior to each turbine test, the measurement system shall be calibrated according to the procedures described below. The manufacturer's operation and calibration instructions are also to be followed as required for each specific analyzer.

6.1.1 Turn on all measurement system components and allow them to warm up until stable conditions are achieved. Next, introduce zero gas and each of the calibration gases described in Section 6.2, one at a time, into the inlet of the probe. The responses of the analyzer to these gases shall be used to establish a calibration curve or to verify the manufacturers calibration curve. The data obtained in these procedures shall be recorded on a form similar to Figure 20.4. If, for the mid-scale gases, the accuracy of the manufacturer's calibration curve or the expected response curve cannot be shown to be ±2 percent of full scale (or better), the calibration shall be considered invalid and corrective measures on the instrument shall be taken. The calibration procedure shall be repeated, using only zero gas and span gas, at the conclusion of test; this allows calculation of zero and span drift (Sections 8.2 and 8.3).

6.2 Calibration Gas Mixtures.

6.2.1 Within one month prior to the turbine test, the NO_x calibration gas mixtures shall be analyzed, using the phenoldisulfonic acid procedure (Method 7) for nitrogen oxides. A minimum of three analyses shall be done, and the average concentration of each gas shall be reported as the true calibration gas value (see Figure 20.9). Alternate procedures may be employed, subject to the approval of the Administrator, to determine the calibration gas concentration.

Figure 20.9

ANALYSIS OF CALIBRATION GAS MIXTURES

CYLINDER GAS COMPOSITION

Reference Method Used______

Date______________________

Low Range Calibration Gas Mixture

Sample 1__________ppm

Sample 2__________ppm

Sample 3__________ppm

Average__________ppm

Mid Range Calibration Gas Mixture

Sample 1__________ppm

Sample 2__________ppm

Sample 3__________ppm

Average__________ppm

High Range (span) Calibration Gas Mixture

Sample 1__________ppm

Sample 2__________ppm

Sample 3__________ppm

Average__________ppm

NOTE.—The NO_x calibration gas mixtures shall contain nitric oxide (NO) in nitrogen. Instruments which require conversion of one nitrogen oxide component to another for total NO_x measurement shall be checked to ensure that this conversion is complete and reproducible, as specified by the manufacturer.

6.2.2 Ambient air may be used as the oxygen span gas. The mid-scale calibration gas concentration shall be certified (by vendor) as being within ±2 percent of the indicated concentration.

[FR Doc.77-28721 Filed 9-30-77;8:45 am]

[6560-01]

[40 CFR Part 60]

[FRL 828-8]

STATIONARY GAS TURBINES

Standards of Performance for New Stationary Sources Extension of Comment Period

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The deadline for submittal of comments on the proposed standards of performance for stationary gas turbines, which were proposed on October 3, 1977 (42 FR 53782), is being extended from December 2, 1977, to January 31, 1978.

DATE: Comments must be received on or before January 31, 1978.

ADDRESSES: Comments should be submitted (preferably in triplicate) to the Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C., attention: Mr. Don R. Goodwin. All public comments received may be inspected and copied at the Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13) Environmental Protection Agency, Research Triangle Park, N.C. 27711, 919-541-5271.

SUPPLEMENTARY INFORMATION: On October 3, 1977 (42 FR 53782), the Environmental Protection Agency proposed standards of performance for the control of emissions from stationary gas turbines. The notice of proposal requested public comments on the standards by December 2, 1977. Due to a delay in the printing and shipping of the Standards Support and Environmental Impact Statement, sufficient copies of the document have not been available to all interested parties in time to allow their meaningful review and comment by December 2, 1977. EPA has received a request from the industry to extend the comment period by 60 days through January 31, 1978. An extension of this length is justified since the printing and shipping delay has resulted in approximately a seven week delay in processing requests for the document.

Dated: December 2, 1977.

EDWARD F. TUERK,
Assistant Administrator for Air and Waste Management.

[FR Doc.77-35293 Filed 12-8-77;8:45 am]